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COAL-FIRED ELECTRICITY GENERATION IN ONTARIO

Ministry of the Environment

Ontario

COAL-FIRED ELECTRICITY GENERATION IN ONTARIO

MARCH 2001

TABLE OF CONTENTS

INTRODUCTION

On May 17, 2000, the Ontario Government announced a moratorium on the sale of all coal-fired electricity plants in the province, pending a review of options for environmental protection. This review of coal-fired electricity generation in Ontario examines and recommends actions for environmental protection. The information in this document will assist the government in making decisions about the environmental safeguards needed for a competitive electricity market.

The document:

- puts air emissions from Ontario's coal-fired power plants into the broader context of air pollution in Ontario;
- provides background information on key air pollutants and individual profiles of each of the province's coal-fired power stations;
- compares the emissions performance of Ontario's electricity sector, fossil fuel fleet and coal fleet to US states within the same airshed;
- and outlines Ontario's current and proposed air emissions reduction measures for the electricity sector.

CHAPTER 1

Air Quality in Ontario

1. AIR QUALITY IN ONTARIO

Air quality is an important part of the quality of life enjoyed by the people of Ontario. Clean air is a vital ingredient for healthy, prosperous communities. According to Ontario's Air Quality Index, the air we breathe is good to very good over 90 per cent of the time.

Air pollution, however, continues to be a considerable challenge. Air quality issues such as smog, acid rain and the threat of climate change are challenges that have to be taken seriously by everyone in Ontario. Air pollution affects Ontario over the short term – during air pollution episodes – and the long term, when air pollutants fall to the ground and accumulate in our lakes, soils, plants and wildlife.

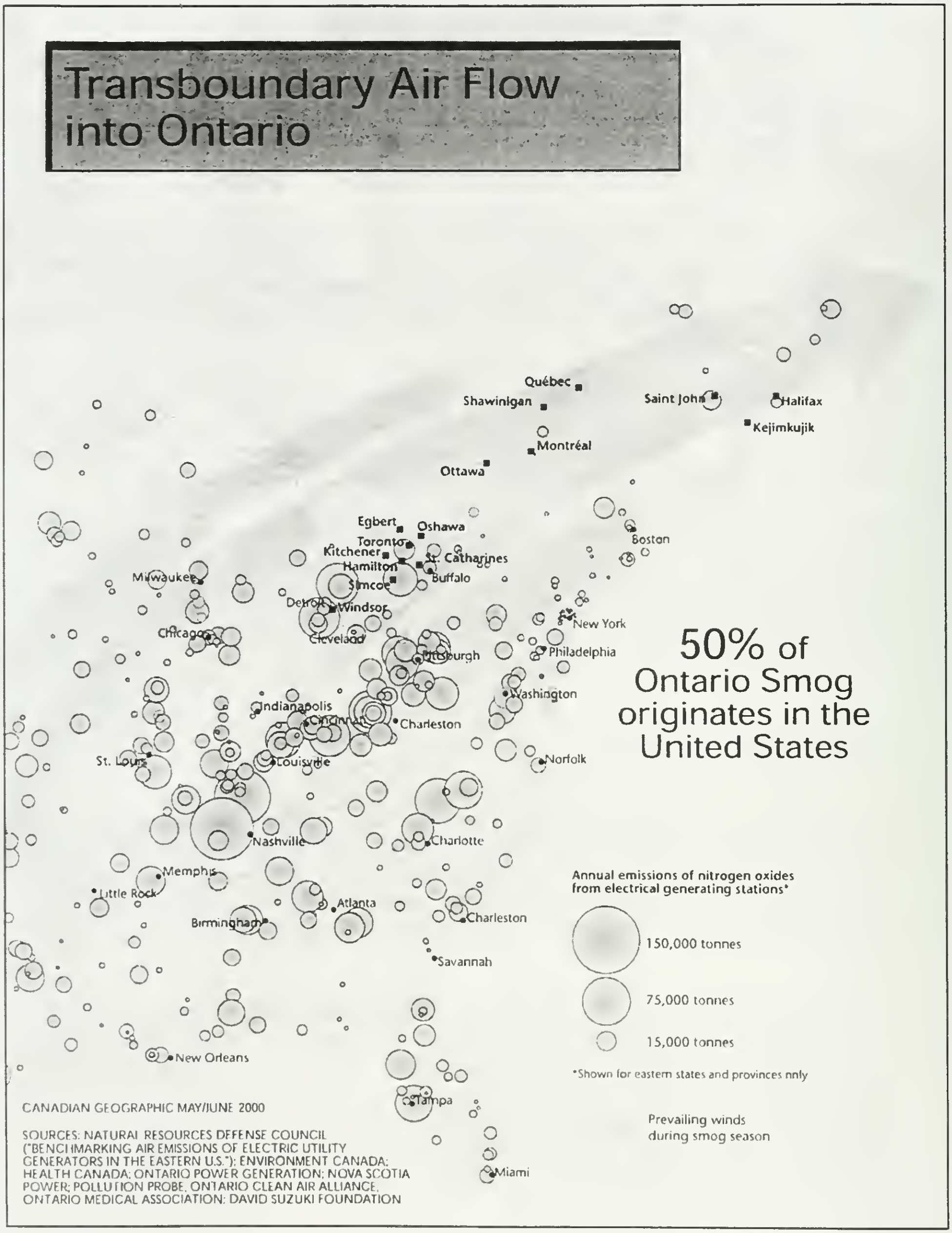
While government plays an important role in protecting the quality of the air we breathe, everyone in Ontario – in industry, business, on the road and at home – has to do their share. Air quality is everybody's business, because we all create air pollution. Fossil fuels such as oil, coal and natural gas are the very engines that drive Ontario's economy and way of life.

We use fossil fuels to power our cars, generate some of the electricity we use, and heat and cool our homes and offices. Ontario's transportation sector (on-road: cars, trucks, buses; off-road: construction equipment), for example, is responsible for approximately 60 per cent of smog-causing nitrogen oxides emissions made in Ontario. Ontario's Power Generation's fossil fuel plants contribute another 15 per cent.

Transboundary air pollution

For the pollutants that cause issues such as smog and acid rain, none of the domestic contributions to air pollution, however, equal the impact of pollutants entering Ontario from the U.S. Prevailing wind patterns make American pollution sources the largest contributors to air pollution in Ontario. More than half of our smog is attributable to pollution from south of the border; particularly during the summer months. (See map "Transboundary Air Flow into Ontario")

Transboundary sources of air pollution can be hard to pin down. Wind movements can carry air pollutants over several hundred metres or thousands of kilometers. Therefore, air pollution has local as well as regional effects. To measure the effects of air pollution movements, the term 'airshed' is often used. Ontario's airshed, for example, is an area that captures upwind emissions sources affecting Ontario's air quality as well as downwind communities affected by Ontario's air pollution. The same definition, on a different scale, can be applied to local airsheds. Since pollution from sources in the U.S. midwest contributes significantly to air pollution in the


Transboundary Air Flow into Ontario
Québec
Shawinigan
Saint John
Halifax
Kejimkujik
Montréal
Ottawa
Egbert
Oshawa
Toronto
Kitchener
Hamilton
St. Catharines
Simcoe
Buffalo
Boston
Milwaukee
Detroit
Windsor
New York
Chicago
Cleveland
Pittsburgh
Philadelphia
50% of Ontario Smog originates in the United States
Washington
Indianapolis
Cincinnati
Charleston
St. Louis
Louisville
Norfolk
Nashville
Charlotte
Memphis
Little Rock
Atlanta
Birmingham
Charleston
Savannah
New Orleans
Tampa
Miami
Annual emissions of nitrogen oxides from electrical generating stations*
150,000 tonnes
75,000 tonnes
15,000 tonnes
*Shown for eastern states and provinces only
Prevailing winds during smog season
CANADIAN GEOGRAPHIC MAY/JUNE 2000
SOURCES: NATURAL RESOURCES DEFENSE COUNCIL ("BENCHMARKING AIR EMISSIONS OF ELECTRIC UTILITY GENERATORS IN THE EASTERN U.S."); ENVIRONMENT CANADA; HEALTH CANADA; ONTARIO POWER GENERATION; NOVA SCOTIA POWER; POLLUTION PROBE, ONTARIO CLEAN AIR ALLIANCE, ONTARIO MEDICAL ASSOCIATION; DAVID SUZUKI FOUNDATION

province, Ontario's airshed extends far into the U.S., including states like Illinois and Missouri. Ontario's airshed also stretches downwind, into Quebec or New York State. By definition, local and regional airsheds overlap.

Air pollution and its effects

The term air pollution means many things to many people. It often stands for a number of very different air quality concerns, chief among them smog, acid rain and climate change. By definition, air pollution means the presence of harmful gases or particles in our air.

While many gases and particles contribute to air pollution, there is a handful of critical air pollutants that deserve special attention because of their toxicity and/or their large contribution to Ontario's most pressing air pollution issues.

Key air pollutants in Ontario are nitrogen oxides (NOx), sulphur dioxide (SO_2), carbon dioxide (CO_2) and mercury (Hg). Both NOx and SO_2 cause acid rain, while the former, along with volatile organic compounds (VOCs), is an important precursor gas to ozone, a major component of smog. Carbon dioxide is a key greenhouse gas, contributing to the threat of climate change, and mercury is a potent nerve-toxin that builds up in the food chain.

Nitrogen oxides and SO_2 can irritate the lungs and lower resistance to respiratory infection, particularly in Ontario's most vulnerable populations: the very young, the old, or people already suffering from respiratory ailments. Both gases can also aggravate cardiovascular disease. Acid rain damages lakes and marine life, forests, crops and physical structures, while smog lowers visibility and can lead to respiratory and cardiovascular problems.

Ontario's air quality strategy

To combat air quality challenges such as smog, acid rain and climate change, the Ontario Government is employing a comprehensive air quality strategy. Some of the initiatives that are part of this approach include the Drive Clean program, Smog Patrol and the province's Anti-Smog Action Plan. Other initiatives such as Ontario's Building Code (which is among the best and most energy-efficient in Canada), regulations to capture greenhouse gas emissions from landfills and a proposal to expand the emissions monitoring and reporting program, also make major contributions.

This tight net of environmental measures is continually being strengthened and cast wider. It includes more industries, communities and individuals than ever before, but never loses sight of three fundamental principles:

- ***Integration***

Since a small number of processes (primarily, the burning of fossil fuels) are directly or indirectly responsible for a variety of air pollution issues, achieving emissions reductions from the main sources of these key pollutants will create a host of co-benefits for air quality. An example: Fully implemented, Ontario's Drive Clean Program is expected to reduce smog-causing emissions, as well as emissions of the greenhouse gas carbon dioxide (CO_2) by 100,000 tonnes annually.

Ontario's air quality strategy also aims to achieve emissions reductions from the widest variety of pollution sources. Incentives to reduce emissions are key to achieving this goal. Innovative programs such as emissions reduction trading offer incentives for voluntary emissions reductions beyond a prescribed limit. Environmental incentive initiatives are poised to play an important policy role in the future. Ontario's monitoring and reporting regulation – which makes emissions from the electricity sector a matter of public record – is another example of an incentive that aims to reduce air pollution.

- ***Comprehensiveness***

Air pollution is being addressed comprehensively by targeting a wide range of key polluters and key pollutants. In light of the large air pollution contribution by transboundary emission movements, Ontario actively and successfully supported the U.S. EPA's legal struggle to implement stringent new emissions limits under its NOx SIP (State Implementation Plan) Call.

Since air pollution affects the health of vulnerable population segments year-round, Ontario is further committed to environmental initiatives that are effective 365 days a year. Ontario's proposed NOx caps for the electricity sector would apply year-round. Nitrogen oxides limits under the U.S. Environmental Protection Agency's SIP Call requirements are seasonal.

- ***Balance***

Every initiative is measured against the yardstick of environmental benefit. Whenever possible, clear and measurable results are the objective for Ontario's environmental actions. Under Ontario's Anti-Smog Action Plan (ASAP), for example, businesses, institutions and municipalities are committed to reducing their smog-causing emissions by 45 per cent.

All individuals and all sectors of society have to do their fair share for reducing or eliminating the emissions that lead to air pollution. Air quality is everybody's business. That's why Ontario's air quality strategy is targeting a variety of sectors simultaneously – transportation, industry, power, residential – while growing in scope to ensure contributions from all sectors and individuals across the province. This balanced and broad-based approach will continue in the future. The Ontario Government is planning a variety of air quality actions which will capture more sectors, communities and individuals.

Environmental protection for Ontario's power sector

Ontario Power Generation (OPG) produces 91 per cent of Ontario's electricity in five nuclear generating stations, six fossil fuel plants and 69 hydroelectric stations. Nuclear and hydroelectric power stations, which in 1999 were responsible for 72 per cent of OPG's electricity output, emit negligible amounts of air pollution. The six fossil fuel power plants produce 28 per cent of OPG's electricity and emit pollutants that contribute significantly to smog, acid rain, and the threat of climate change.

On May 17, 2000, the Ontario Government announced a moratorium on the sale of coal-fired plants and initiated this review. The review is part of the government's ongoing commitment to ensure that effective environmental measures are developed in preparation for the future opening of the electricity market. Initial proposals were announced on January 24, 2000, including:

- *Stringent new emissions limits (caps) for NOx and SO_2* – the new limits would cap total annual emissions from coal and oil-fired electricity generating stations.

- *Emissions Reduction Trading* – a system that would offer incentives to emitters in Ontario's airshed who go beyond their emission or reduction targets.

- *A commitment to meeting or exceeding U.S. Environmental Protection Agency emission standards* – when new EPA standards are implemented, Ontario would modify its regulations accordingly if the adoption of those standards will result in lower emissions in Ontario.

- *Expanding emissions limits to other sectors* – As part of its contribution to the Canada-Wide Acid Rain Strategy for Post-2000, the Ontario Government committed to a target of reducing total SO_2 emissions by 50 per cent by 2015. The province also re-affirmed its commitment to the targets of its Anti-Smog Action Plan, which include reducing provincial emissions of NOx and volatile organic compounds (VOCs) by 45 per cent over their 1990 levels by 2015.

- *Emissions Performance Standards* that would apply to all electricity sold in Ontario, whether imported or domestically generated – this initiative would set a maximum level of air pollution allowed to accompany a unit of electricity generation.

- *Expansion of the Environmental Assessment Act* (EAA) to cover the entire electricity sector – assessments under the EAA would be triggered by the environmental significance of a proposed electricity project, rather than its status as a public or a private venture.

- *Mandatory Monitoring and Reporting* on pollutants, including the full suite of greenhouse gases. A list of 28 pollutants already applies to Ontario's electricity sector.

The Ontario Government has proposed an expansion of the list of pollutants and the additional of sectors to be included under the regulation.

As is the case for Ontario's comprehensive air quality strategy, environmental protection for Ontario's electricity sector will undergo continuous improvements. The Ontario Government will continue to take real, meaningful steps to cut air pollution across all sectors.

CHAPTER 2

Air Pollution in Ontario

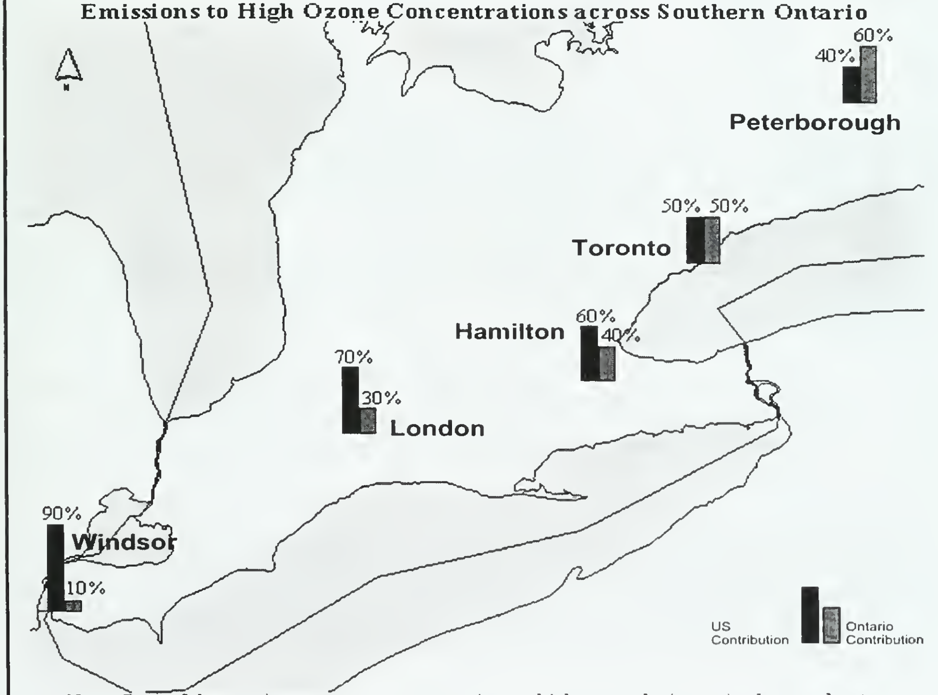
Sources and Potential Health Effects

2. AIR POLLUTION IN ONTARIO SOURCES AND POTENTIAL HEALTH EFFECTS

Transboundary vs. domestic air pollution

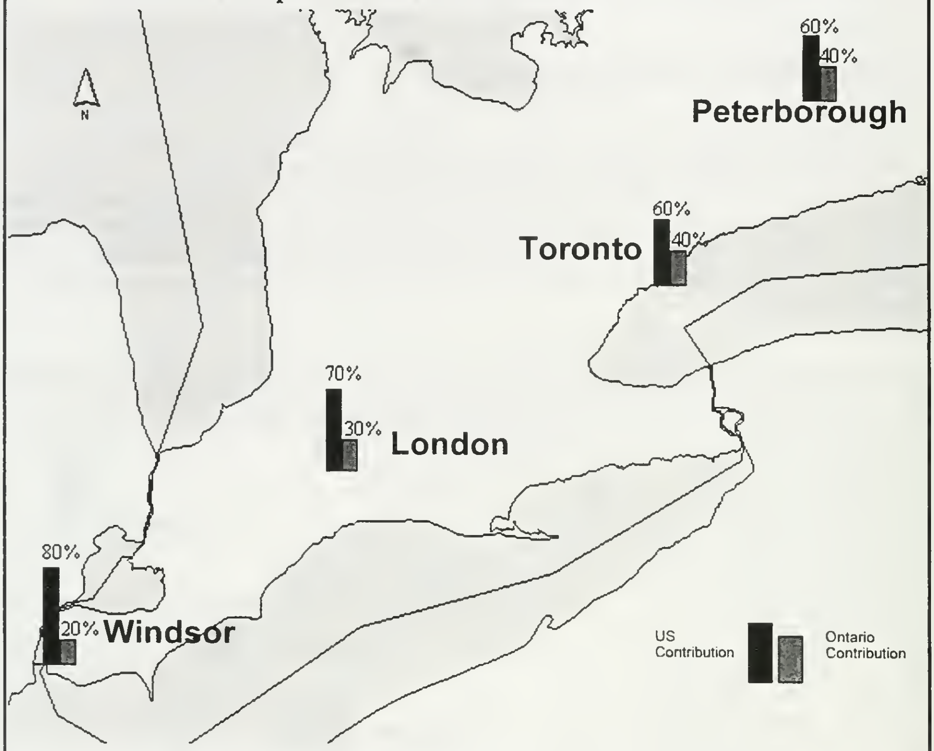
Smog is a hazy mixture of a large number of air pollutants. It is made up of contaminants emitted directly into the atmosphere, and secondary pollutants such as ozone (O_3) and inhalable particulate matter (PM) that are the products of atmospheric chemical reactions. Both ozone and inhalable particles are major components of smog. The precursor gases for ozone are nitrogen oxides (NOx) and volatile organic compounds (VOCs), while sulphates – which make up a large part of the inhalable particles in Ontario's air – are the secondary product of sulphur dioxide (SO_2) emissions.

Approximate Contributions of U.S. and Ontario Precursor NO_x and VOC Emissions to High Ozone Concentrations across Southern Ontario



Note: Part of the maximum ozone concentrations which occur during episodes are due to background ozone in the atmosphere. The above percentage contributions refer to only the portion of the ozone resulting from precursor NO_x and VOC emissions in the US and Canada [adapted from "Atmospheric Science Expert Panel Report: Sulphur in Gasoline and Diesel Fuels Study".]

Approximate Contributions of U.S. and Ontario Precursor SO_2 Emissions to Airborne Sulphate Concentrations Across Southern Ontario



Note: SO_2 emission sources in some urban communities can contribute to local sulphate concentrations which in turn would reduce the percentage contribution of U.S. sources. [Adapted from "Towards a National Acid Rain Strategy" and " A Compendium of Current Knowledge on Fine Particulate Matter in Ontario".]

On average, more than half of the ozone and particulate matter in Ontario's air is the result of precursor gases which are blown across the border from U.S. emissions sources by prevailing wind patterns. Under the umbrella of this 50 per cent average, however, the regional impacts of imported U.S. pollutants for the most populated areas of Ontario can climb even higher (see maps above).

If the wind blows from Detroit, Michigan, for example, smog episodes in neighbouring Windsor are almost entirely the result of transboundary pollution. The rest of southwestern Ontario still

receives 70 to 90 per cent of its ozone and 70 to 80 per cent of its sulphate due to precursor gases blown in from the U.S.

Most of the air pollution generated right here in Ontario comes from burning fossil fuels in automobiles, furnaces, industrial settings and power generation.

Ontario's key air pollutants and their sources

Nitrogen oxides (NOx)

All combustion (burning) processes produce nitrogen oxides. Nitrogen oxides are highly reactive gases that play a crucial part in the formation of ozone (smog) and acid rain. They transform in the air to form gaseous nitric acid, nitrate salts and toxic organic nitrates.

Nitrogen oxides can irritate the lungs and lower resistance to respiratory infection, particularly in people who suffer from asthma or bronchitis.

As precursor gases to ozone (O_3) – the main component of smog – NOx are indirectly responsible for the potential health effects of smog, which include irritation of the respiratory tract and the eyes, chest tightness, coughing and wheezing. People with pre-existing respiratory disorders such as asthma and chronic obstructive lung disease are at a higher risk, as are children playing outdoors during the summer. Ozone also causes crop damage and leaf damage in garden plants and trees.

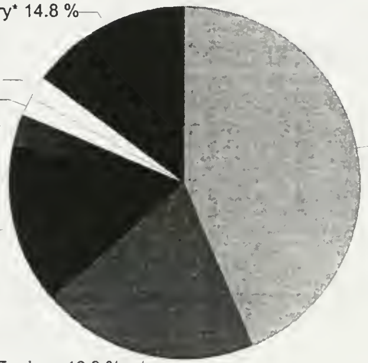
Nitrogen oxides, when transformed into nitric acid, contribute to acid rain and as such can corrode metals, fade fabrics and degrade rubber. Acid rain also damages lakes, marine wildlife, trees and crops.

Sources of NOx

Domestic

In 1999, Ontario's transportation sector (rail, air, marine, passenger vehicles, trucks, buses) was responsible for 43.5 per cent per cent of Ontario's NOx emissions. Off-road engines in machines such as snowmobiles, all-terrain vehicles (ATVs), construction equipment, etc., contributed another 19.9 per cent. Ontario Power Generation's fossil fuel power plants were responsible for 14.7 per cent of Ontario's NOx emissions. The remaining 22 per cent is the result of a large variety of industrial, commercial and residential emitters (see chart on following page).

Domestic Sources of NOx Emissions
Ontario, 1999



* Electricity Generation does not include independent power producers. Manufacturing and Primary Industry includes point source estimates.

Transboundary

Emissions of NOx from sources in the U.S. are responsible for about half of the ground level ozone experienced during episodic conditions in Ontario.

Sulphur dioxide (SO_2)

Sulphur dioxide is a colourless gas which smells like burnt matches. It can be oxidized to sulphur trioxide, which in the presence of water vapour is readily transformed into sulphuric acid mist. Once released into the air, SO_2 can transform into airborne sulphates, harmful inhalable particles which can aggravate bronchitis, asthma, cardiovascular ailments and lung disease. Particles are also responsible for corrosion, soiling, damage to vegetation and visibility reduction. Sulphur dioxide can further be transformed into airborne acid particles which are precursors to acid rain. (For the environmental effects of acid rain, see NOx).

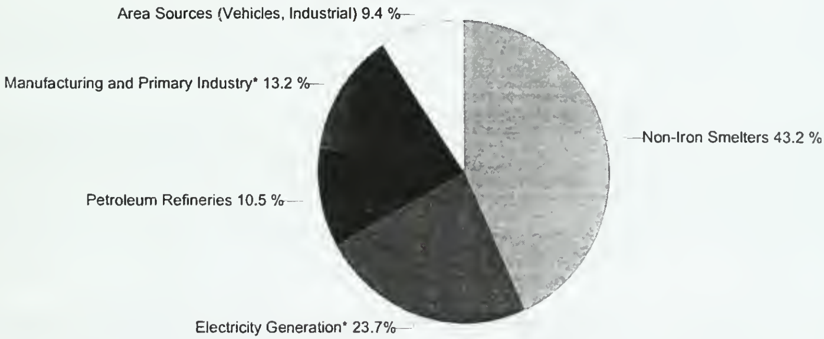
Health effects caused by exposure to high levels of SO_2 include breathing problems, respiratory illness, changes in the lung's defences and worsening respiratory and cardiovascular disease. People with asthma or chronic lung or heart disease are the most sensitive to SO_2. Sulphur dioxide also damages trees and crops.

Sources of SO_2

Domestic

In 1999, non-iron smelters in the province accounted for 43.2 per cent of Ontario's SO_2 emissions. OPG's Fossil fuel power plants were responsible for 23.7 per cent, while petroleum refineries and manufacturing and primary industry added another 10.5 per cent and 13.2 per cent, respectively. Various area sources (a large number of small emitters) added 9.4 per cent. (see chart.)

Domestic Sources of SO2 Emissions
Ontario, 1999



* Electricity Generation does not include independent power producers. Manufacturing and Primary Industry includes point source estimates.

Transboundary

Emissions of SO_2 from sources in the U.S. are responsible for 50-60 per cent of the airborne sulphate in the greater Toronto and Hamilton areas.

Mercury (Hg)

Mercury is a toxic heavy metal that exists as a trace element in certain fossil fuels, including coal. Mercury enters the environment from both natural and man-made sources. Although not fully understood, it is generally believed that natural and anthropogenic sources contribute about equally to a global mercury pool, which circulates in the Earth's atmosphere. This global mercury pool is fed by emissions from countries such as the United States, China and Russia. Once released into the air, forms of mercury may be deposited locally, or become part of the global pool and be carried thousands of kilometers from their source. Mercury, therefore, is a global pollutant with global effects.

Mercury is a neurotoxin that bio-accumulates in the food chain. It has become the subject of growing public health concern based on scientific studies that suggest that even low levels of exposure can cause neurological and developmental impairment in the fetus and young child.

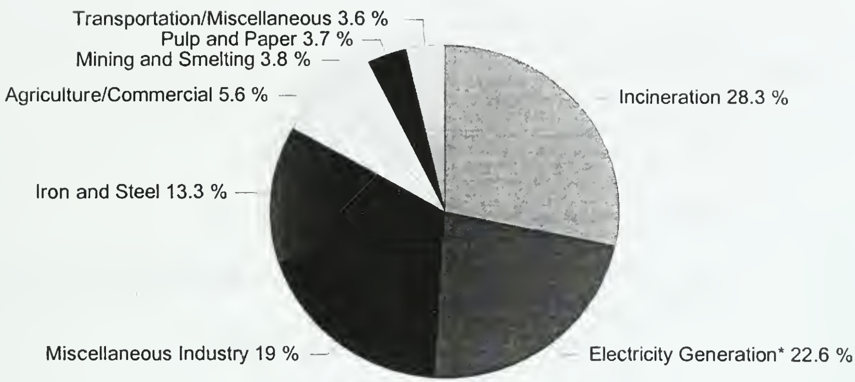
Mercury impacts in Ontario and in Canada include restrictions on eating sportfish, resulting lifestyle changes for aboriginal groups and mortality and reproductive impacts in loon and otter populations. In the Great Lakes, mercury is the cause of 20-60 per cent of sport fish consumption restrictions. It is the cause of 99 per cent of the sport fish consumption restrictions in inland lakes in Ontario, Quebec, New Brunswick, Nova Scotia, Manitoba and Saskatchewan.

As of 2000, Ontario had reduced provincial mercury emissions by 78 per cent of 1988 levels. Under the Canada-Wide Standards (CWS) process, Ontario has already set mercury release limits for incinerators and is currently developing mercury standards for coal-fired power generation, which are expected to be finalized by the fall of 2002.

Sources of Hg

In 1999, incineration was the largest contributor to mercury air pollution in the province. It accounted for 28.3 per cent of overall Hg emissions. Ontario Power Generation's fossil fuel plants were responsible for 22.6 per cent, while a variety of industrial sources in Ontario accounted for another 19 per cent. Iron and steel manufacturing added 13.3 per cent to mercury air pollution in the province, and the agricultural and commercial sectors 5.6 per cent (see chart on following page).

Domestic Mercury Air Emissions
Ontario Sources, 1999



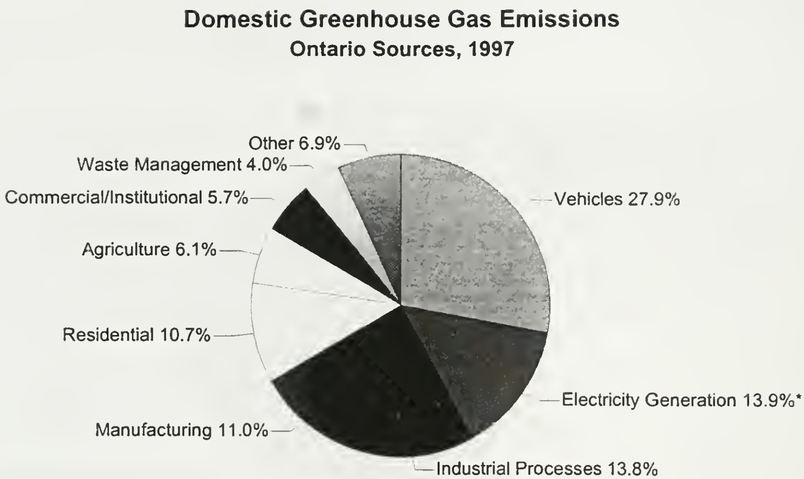
* does not include independent power producers.

Greenhouse gases

Greenhouse gases are responsible for climate change, potentially leading to higher average global temperatures and the accompanying extreme weather events, climate zone shifts, agricultural damage, etc. Greenhouse gases are global pollutants with global effects.

Sources of greenhouse gases (in CO_2 equivalents)

In 1997, Ontario's millions of vehicles (automobiles, off-road vehicles, trucks, airplanes, trains, etc.) contributed 27.9 per cent to Ontario's greenhouse gas emissions totals. Ontario Power Generation's fossil fuel power plants were responsible for 13.9 per cent, while industrial processes added 13.8 per cent of provincial greenhouse gases. Manufacturing was responsible for 11 per cent, while residential sources (home furnaces, etc.) added another 10.7 per cent. Agriculture added 6.1 per cent of CO_2 equivalents, while the commercial and institutional sector accounted for 5.7 per cent (see chart on following page).



*does not include independent power producers. OPG fossil fuel stations only.

CHAPTER 3

Ontario's Electricity Sector and Fossil Fuel Generation

3. ONTARIO'S ELECTRICITY SECTOR AND FOSSIL FUEL GENERATION

Overview

In 1999, 143.1 TWh of electricity was fed into the provincial power grid by Ontario-based generators. This includes 131.5 TWh of production from Ontario Power Generation (OPG) and 11.6 TWh from Independent Power Producers. In 1999, Ontario imported about 7.7 TWh of electricity and exported approximately 5.9 TWh, primarily to Michigan, yielding net imports of 1.8 Th.

OPG's mix of generating assets currently in operation includes nuclear, coal, oil/gas-fueled and hydroelectric generation with a total capacity of 25,800 MW. In addition, OPG has capacity which is currently not operating. This includes nuclear capacities of 2,060 MW at Pickering and 3,076 at Bruce-A. Due to recent reductions in nuclear power generation in the province, OPG's fossil fuel plants have increased power production to meet power demands. Independent Power Producers (IPPs) are generators that have contracts with the Ontario Electricity Financial Corporation (OEFC) to deliver defined amounts of capacity and energy. IPP generation includes hydroelectric as well as waste-fueled and natural gas-fueled thermal generation. IPP installations range in size from about 1MW to 165 MW with a total capacity of 1,766 MW.

In addition to OPG and IPPs, there are other electricity generators in the province that operate to supply electricity for their own internal use. These supplies are generally referred to as self-generation or internal-generation and are not made available to the provincial grid. The installed self-generation capacity in Ontario is approximately 1,500 MW. Self generation capacity includes about 986 MW in the industrial sector of which only 517 MW is actually operated due to costs, 400 MW with other utilities, and 120 MW with municipal electric utilities and the commercial sector.

OPG Five Year Generation Summary

	1995		1996		1997		1998		1999	
	Total TWh	% of Total	Total TWh	%of Total	Total TWh	% of Total	Total TWh	% of Total	Total TWh	% of Total
Hydroelectric	35.3	25.5	37.6	28	36.4	27.8	31.9	25.3	33.6	25.6
Fossil	16.7	12.1	19	14.2	24.4	18.6	34.2	27.2	36.5	27.8
Nuclear	86.2	62.4	77.8	57.8	70.3	53.6	59.9	47.5	61.4	46.7
Total	138.2	100	134.4	100	131.1	100	126	100	131.5	100

Notes: 1 MWh is approximately equal to the amount of electricity used by one household in one month;
1 TWh is approximately equal to the amount of electricity used by 80,000 households in one year.

Generating units are classified into three categories of operating mode:

- **Base load capacity** operates to satisfy relatively constant demand;
- **Peaking capacity** operates intermittently to provide power during periods of maximum demand;
- **Intermediate capacity** operates fewer hours than base load capacity, but more than peaking capacity.

Fossil fuel electricity generation

Ontario Power Generation's fossil fuel generating stations are used to provide intermediate and peaking capacity to match fluctuations in electricity demand. While their short run marginal costs are high, these stations offer greater operational flexibility to take advantage of market opportunities compared with nuclear generating stations which are base load facilities that provide little or no operational flexibility. Fossil fuel generation has typically represented the smallest part of OPG's generation mix, operating primarily to satisfy peak demands. As a result of recent reductions in nuclear generation, OPG's fossil fuel generation has increased to support intermediate and base load needs.

Ontario Power Generation owns and operates six fossil fuel stations. A total of 23 generating units are currently in service with a combined power capacity of approximately 9,700 MW, representing approximately 38 per cent of its total in-service capacity. Coal-powered generating units at Nanticoke, Lambton, Lakeview, Thunder Bay and Atikokan account for approximately 7,600 MW of in-service capacity. Dual-fueled (oil/natural gas) generating units at Lennox account for approximately 2,100 MW of in-service capacity.

The location of each station is as follows:

- Lakeview is located in Mississauga, on the shore of Lake Ontario;
- Nanticoke is on the north shore of Lake Erie;
- Lambton is south of Sarnia on the St. Clair River;
- Lennox is near Kingston;
- Thunder Bay is on Lake Superior; and
- Atikokan is in northwestern Ontario between Lake Superior and the Manitoba border.

Table 3.1 - Summary of Fossil Fuel Generating Facilities

Station	No. of In-Service Units	Net In-Service Capacity (MW)	% of Fossil Capacity	Net Energy TWh (1999)	% of Fossil Net Energy (1999)	Net Capacity Factor (%) (1999)	Capacity Factor Since In-Service	Original Unit In-Service Date(s)(1)
Nanticoke	8	3920	40.4	18.9	52.4	55	42	1973-1978
Lambton	4	1975	20.4	9	24.9	52	47	1969-1970
Lakeview	4	1140	11.7	3.2	8 9	32	28	1962-1969
Lennox	4	2140	22.1	2.3	6.4	12	6	1976-1977
Thunder Bay	2	310	3.2	1.6	4.4	59	47	1981-1982
Atikokan	1	215	2.2	1.1	3	59	43	1985
TOTAL	23	9700	100	36.1	100			

Notes:

- All units are coal-fired except at Lennox. Lennox has four dual-fueled (oil/natural gas) units capable of burning natural gas and oil.
- All units at Lambton are coal-fired. Extensive rehabilitation has been completed on Units 3 and 4

Ontario Power Generation's major fossil fuel plants were constructed during a period of high electricity demand when their output capacity was expected to be fully utilized. However, lower than expected growth in demand led to an oversupply of capacity and thus, OPG's coal plants were primarily used to meet demand during peak periods.

To meet demand in the face of declining nuclear generation with the shutdown of the Bruce A and Pickering A stations, fossil fuel generation increased between 1995 and 1999. To provide the majority of additional fossil fuel generation, the scrubber-equipped units at Lambton and the eight units at Nanticoke have operated essentially as base load units since 1995 and 1998, respectively. In 1998, OPG commenced an asset enhancement program at these stations designed to improve mechanical reliability, safety and environmental performance.

Air pollution and fossil fuel generation

Air pollution from Ontario's power sector is generated almost exclusively in coal or oil/natural gas-fired stations. Domestically, OPG's six fossil fuel stations account for the following proportion of total domestic provincial emissions:

- 14.7 % of nitrogen oxides (NOx)
- 23.7 % of sulphur dioxide (SO_2)
- 13.9 % of greenhouse gases (CO_2 equivalents)
- 22.6 % of mercury (Hg)

As part of its efforts to reduce air emissions, OPG has already undertaken a number of initiatives including:

- increasing its use of low-sulphur coal;
- upgrading the low-NOx burners on all eight units at Nanticoke;
- converting all four units at Lennox to dual-fueling so that natural gas or oil can be used. Natural gas has no SO_2 emissions and lower NOx emissions than oil;
- installing scrubbers in two units at Lambton to reduce flue gas SO_2 content, completing combustion process modifications for two units and installing enhanced boiler controls in two units to reduce NOx emissions; and
- committing to the installation of four NOx removal technologies (SCRs) on two units at Lambton and two units at Nanticoke and to the installation of low-NOx burners at the Lakeview station.

Ontario Power Generation has reduced the average NOx emission rate from its fossil fuel stations by 36 per cent since 1983 and 22 per cent since 1990 (as of 1999). Sulphur dioxide emission rates have been reduced by 68 per cent since 1983.

Emission rates and total emissions for NOx, SO_2, CO_2 and mercury for each of OPG's fossil fuel stations are provided in Table 3.2.

Table 3.2 - OPG Fossil Fuel Station Emission Rates and Total Emissions (1999)

Station	Net Energy	Emission Rates				Emissions							
	TWh	NOX kg/MWh	SO2 kg/MWh	CO2 kg/MWh	Hg g/MWh	NOX kt	%	SO2 kt	%	CO2 kt	%	Hg kg	%
Lambton	9.0	1.42	3.03	870	0.015	12.78	25.2	27.3	19.4	7,830	24.7	135.0	21.4
Nanticoke	18.9	1.28	4.3	890	0.014	24.19	47.8	81.3	57.7	16,821	53.0	264.6	42.0
Lakeview	3.2	2.6	5.5	910	0.026	8.32	16.4	17.6	12.5	2,912	9.2	83.2	13.2
Lennox	2.3	0.89	0.7	660	n.a.	2.05	4.0	1.61	1.1	1,518	4.8	n.a.	n.a.
Thunder Bay	1.6	1.27	4.7	950	0.050	2.03	4.0	7.52	5.3	1,520	4.8	67.1	12.7
Atikokan	1.1	1.18	4.98	1,010	0.061	1.30	2.6	5.48	3.9	1,111	3.5	63.0	10.7
Total	36.1	1.41	3.9	880	0.017	50.7	100	140.7	100	31,712	100	629.9	100

% is percentage of emissions from all six OPG fossil fuel stations. NOx is reported as NO.

Lakeview Generating Station

Characteristics: Lakeview is located in Mississauga, on the shore of Lake Ontario. The oldest station in OPG's fossil fuel fleet, the plant's units entered into service during the period from 1962 to 1969. Lakeview's book retirement date is 2006. In practice, however, the station's lifespan can be extended indefinitely with overhauls and replacement of components.

Current capacity is 1,138 MW from four coal-fired units (Units 1, 2, 5 and 6). Each unit consists of a coal-fired boiler, a steam turbine and a generator. Four generating units at Lakeview representing approximately 1,100 MW of power capacity were taken out of service in 1992 as surplus capacity. Significant expenditures would be required to reactivate and operate these units.

System Needs: Lakeview provides two basic functions to support system reliability. It provides capacity to meet overall system loads and reactive support to maintain local voltages. The high demand for electricity in the Toronto area has meant that Lakeview is needed during peak periods to meet system demand. The Independent Electricity Market Operator (IMO) reports that, if some of the Darlington and Pickering units were not available during summer peak period, Lakeview would be necessary to maintain system reliability in the Greater Toronto Area.

Plans for Lakeview: Current plans are for Lakeview to continue its role as providing power during peak periods and as required for system reliability. Lakeview's in-service units were given extensive overhauls in the early 1990s. These units have an estimated remaining life of five to 10 years.

Electricity Generation and Emissions: In 1999, Lakeview produced 3.2 terawatt-hours (TWh) of electricity, operating at 32 per cent of in-service capacity. The heat rate (a measure of efficiency) of Lakeview was 10,800 kilojoules (kJ) per kWh.

Pollution control technologies currently in place for Lakeview Units 1 and 2 include:
- boiler tuning and optimization using artificial intelligence to advise operators on how to minimize NOx formation;
- electrostatic precipitators controlling particulate emissions; and
- low-NOx burners currently scheduled for installation in 2001 at a cost of $4.4 million

Units 5 and 6 have the following:
- artificial intelligence system which directly controls the boiler to minimize NOx formation. Estimated reduction of 10 per cent at full load, and higher reductions at partial loads; and
- low-NOx burners installed and currently being commissioned. The expected emission rate for these low-NOx units is 1.3 kilograms of NOx per MWh (up to a 50 per cent reduction).

Lakeview is part of the Greater Toronto Area (GTA), which is home to about five million people. This heavily urbanized area requires substantial infrastructure to support business and industry, and a viable transportation network. All of this requires power – and with the fossil-fueled generation of power comes air pollution. A comparison using recent GTA emissions inventories for NOx and SO_2 emissions indicates Lakeview accounts for 26 per cent of the GTA's SO_2 emissions and 8 per cent of NOx emissions.

The Lakeview station is a major source of local mercury emissions. Lakeview emitted 83 kg/yr in 1999 and is currently the second-largest emitter in the GTA. The largest is the KMS Peel incinerator in Brampton, at 140 kg/yr. The Peel incinerator is upgrading and soon its emissions will be reduced to 25 kg/yr, leaving Lakeview as the largest mercury polluter in the area.

Another facility, the Ashbridges Bay sewage sludge incinerator, emits about 68 kg/yr, but is slated to close in 2001. Operating as it presently does, by December 2001, Lakeview would clearly be the single largest mercury source in the GTA, emitting triple the amount of the next biggest source.

The coal presently burned (characterized by 1,450 ppm chloride, 0.08 ppm mercury) produces a high proportion of ionic mercury - about 65 per cent of the total emitted. Ionic mercury tends to be deposited locally (i.e., within 48 km of its point of origin).

Lambton Generating Station

Characteristics: Located south of Sarnia on the St. Clair River, Lambton entered service in 1969. Current capacity of Lambton is 1,975 MW in four units, each consisting of a coal-fired boiler, a steam turbine and a generator.

System Needs: Lambton maintains acceptable voltages and load security in the south-western system. It can also be required to maintain voltage stability after a contingency in Southern Ontario – a contingency is a problem with generation or transmission that affects electricity supply – and for safety under winter icing conditions.*

* *Winter icing affects electricity transmission along power lines. It can lead to short circuits on high voltage transmission equipment, reducing transmission capacity. When transmission is affected, local generation must supply more of the local demand.*

Plans for Lambton: Lambton is expected to continue its role as an intermediate power provider for Ontario and possibly export markets. Apart from fuel conversion, changes to the station are not likely to change this role. Heavy use of the two units equipped with flue gas de-sulphurization (FGD) technology is expected.

The book retirement date for the Lambton station is 2010. In practice, however, its life can be extended indefinitely with overhauls and replacement of components. Extensive rehabilitation on two units have extended their estimated life to 50 years.

Electricity Generation and Emissions: In 1999, Lambton produced 9.0 TWh of electricity, operating at 52 per cent of in-service capacity. The heat rate for Lambton in 1999 was 10,070 kJ/kWh. Ontario Power Generation has announced plans to install selective catalytic reduction systems on two of Lambton's units.

Installed pollution control technologies include:

- flue gas de-sulphurization on Units 3 and 4 to reduce sulphur, at a cost capital cost of more than $450 million;
- optimized burn controls (artificial intelligence) on all units, achieving a 10 to 20 per cent NOx reduction, at a cost of $2 million;
- combustion process modifications on Units 3 and 4, achieving a 30 to 35 per cent NOx reduction, at a cost of $20 million. Similar modifications are planned for Units 1 and 2 in 2001; and
- units 1 and 2 currently operate on low-sulphur bituminous coal.

The Sarnia area is home to a large group of chemical industries in addition to the Lambton station. On occasion, meteorological conditions are such that the emissions of these industries can lead to unacceptably high pollution levels. The Ministry of the Environment, in conjunction with the Lambton Industrial Society (LIS), has established the Lambton Industrial Meteorological Alert System (LIMA). When a LIMA alert is called, major industries are required to curtail their production or switch to lower-sulphur-content fuel.

The transboundary impact of pollution from U.S. sources on this area is also significant.

Nanticoke Generating Station

Characteristics: Located in Haldimand County on the shore of Lake Erie, Nanticoke entered service in 1973. Current capacity of the plant is 3,920 MW in eight units, each consisting of a coal-fired boiler, a steam turbine and a generator.

System Needs: Nanticoke may be required to maintain acceptable voltage in southern Ontario and to support interface flows* to supply the Toronto area in heavy load conditions.

** The electrical transmission grid in Ontario is divided into several sections. An interface is the point of connection between these sections. The interface flow is the power going through the connection.*

Plans for Nanticoke: Nanticoke is expected to continue its role as a major intermediate power provider for the Ontario market. Changes to the station, apart from fuel conversion, are not likely to affect this role.

The expected book retirement date for Nanticoke is 2015. In practice, however, its lifespan can be extended indefinitely with overhauls and replacement of components.

Electricity Generation and Emissions: In 1999, Nanticoke produced 18.9 TWh of electricity, operating at 55 per cent of capacity. The heat rate of Nanticoke was 10,183 kJ/kWh.

Existing pollution control technologies include low-NOx burners on all eight units, installed at a cost of $16 million. Ontario Power Generation has announced plans to install selective catalytic reduction systems on two of Nanticoke's units.

Nanticoke, like Lambton, is located in a region of southern Ontario that is particularly affected by transboundary pollution from the U. S.

The Nanticoke station is an active member of the Nanticoke Environmental Committee (NEC) comprised of the other two major industries in the area, Lake Erie Steel and Imperial Oil's Nanticoke Refinery. The Ministry of the Environment and Environment Canada are also members.

The members of the committee are responsible for the Nanticoke Air Monitoring Network. This committee meets on regular basis and is supported financially by the members to operate the air monitoring network. The ministry compiles an annual report from the air monitoring data which is presented to local-area residents.

Atikokan Generating Station

Characteristics: Atikokan is located in northwestern Ontario between Lake Superior and the Manitoba border. It entered service in 1985. The current capacity of Atikokan is 215 MW in one unit, consisting of a coal-fired boiler, a steam turbine and a generator.

System Needs: When power is transmitted over long distances, it can become unstable. Atikokan is sometimes used to stabilize power flowing from Manitoba into southern Ontario.

As well, the local (West) system requires some local generation at all times for voltage support and transmission security, which is supplied by Atikokan, Thunder Bay, and the northwest hydro stations. The electrical system requires constant attention to demand and supply, with adequate reserves of generation ready to step in at a moment's notice, and generation supplying power at the right locations to maintain voltage.

Plans for Atikokan: Atikokan is expected to continue its role as an intermediate power provider. Changes to the station, apart from fuel conversion, are unlikely to change this role. The book retirement date for Atikokan is 2025. In practice, however, its life can be extended indefinitely with overhauls and replacement of components.

Electricity Generation and Emissions: In 1999 Atikokan produced 1.1 TWh of electricity, operating at 59 per cent of capacity. The heat rate of Atikokan was 10,605 k J/kWh. Atikokan was constructed with a low-NOx burner and currently operates on low-sulphur lignite.

Thunder Bay Generating Station

Characteristics: Located in Thunder Bay on the shore of Lake Superior, the plant's active units entered service in 1981. Current capacity of Thunder Bay is 310 MW in two units. Each unit consists of a coal-fired boiler, a steam turbine and a generator.

System Needs: Thunder Bay can be required for voltage support and local load security. A former generator is operated as a synchronous condenser, providing reactive power for voltage support. A synchronous condenser is a converted generator that cleans up the power quality of the electricity supply. Electrical equipment like motors feed some distortion into the local electrical system, putting non-synchronized energy into the system. The synchronous condenser removes this distortion by putting this energy back into synch.

The local (West) system requires some local generation at all times for voltage support and

transmission security, which is supplied by Atikokan, Thunder Bay, and the northwest hydro stations.

Plans for Thunder Bay: Current plans for Thunder Bay are to continue its role as an intermediate power provider. Changes to the station, apart from fuel conversion, are unlikely to affect this role. The nominal life of the station is 40 years. Thunder Bay's book retirement date is 2021. In practice, however, its life can be extended indefinitely with overhauls and replacement of components.

Electricity Generation and Emissions: In 1999, Thunder Bay produced 1.6 TWh of electricity, operating at 59 per cent of capacity. The heat rate of Thunder Bay in 1999 was 10,611 k J/kWh. Thunder Bay operates on low-sulphur lignite coal.

Lennox Station (Gas and Oil)

N.B.: Gas/Oil-fired electricity stations such as Lennox are not the focus of this review. The key pollutants emitted by these stations are NOx and CO_2. For both gases, however, the emission rates are substantially lower than for coal-fired stations (See Table 3.2)

Characteristics: Lennox is located on Lake Ontario, approximately 30 km west of Kingston. The station entered service in 1976. It was placed in reserve from 1982 to 1987. Current capacity of Lennox is 2,140 MW in four units. Each unit consists of a dual gas and oil-fired boiler, a steam turbine and a generator.

System Needs: Lennox provides overall system capacity, and addresses transmission line issues and restrictions for the area east of Toronto.

Plans for Lennox: As the only major oil and gas-fired facility in Ontario, Lennox provides fuel diversity and relatively inexpensive peaking capacity. Recently, OPG undertook conversion of two burners to allow fueling by gas or oil. All units now have this capability.

Electricity Generation and Emissions: In 1999, Lennox produced 2.3 TWh of electricity, 1.0 TWh on oil and 1.3 TWh on gas. Overall, Lennox operated at 13 per cent of capacity with a heat rate of 10,800 kJ/kWh.

CHAPTER 4

Benchmarking Ontario's Emissions Performance

A Comparison with 19 Nearby U.S. Jurisdictions

4. BENCHMARKING ONTARIO'S EMISSIONS PERFORMANCE: A COMPARISON WITH 19 NEARBY U.S. JURISDICTIONS

More than half of Ontario's air pollution is blown across the border from upwind sources in the U.S. – particularly those that are located in midwestern U.S. states. Emissions levels and efforts to reduce emissions from upwind states are major air quality concerns for Ontario and many northeastern states that also suffer from transboundary air pollution. Like Ontario, many northeastern states are taking actions to improve air quality that go much further than the actions of many midwestern states.

The following section compares Ontario's NOx and SO_2 emissions and emissions targets for the electricity sector to those of 19 jurisdictions in the U.S. northeast and midwest. These states are referred to as the U.S. Pollution Emission Management Area (PEMA) under the Ozone Annex, which is part of the Canada/U.S. Air Quality Agreement.

Ontario's NOx and SO_2 emissions are compared to the U.S.19 PEMA jurisdictions on four levels:

I. **Total provincial and U.S. jurisdiction NOx and SO_2 emissions from all sectors;**
II. **Total NOx and SO_2 emissions from electricity sectors;**
III. **Total NOx and SO_2 emissions from fossil fuel generated electricity; and**
IV. **Total NOx and SO_2 emissions from coal-fired electricity.**

For the purpose of comparison, select U.S. emission control programs south of the border are also included in this section

I. Total provincial and U.S. jurisdiction NOx and SO_2 emissions from all sectors

Compared with the 19 jurisdictions in the U.S. PEMA (see Table 4.1 and Figure 4.1.A), Ontario is the eighth-largest emitter of NOx and the seventh-largest emitter of SO_2.

Ohio is the largest source of both pollutants, emitting almost double Ontario's emissions of NOx and nearly triple the amount of SO_2. The amount to which a particular jurisdiction relies on coal for its power has a big impact on that jurisdiction's total emissions of NOx and SO_2.

Because Ohio relies on coal for more than 87 per cent of its power, the state as a whole has substantial total emissions of NOx and SO_2. Ontario relies on coal for less than 24 per cent of its power production. Therefore, the total provincial emissions of NOx and SO_2 are much lower than for many neighbouring states in Ontario's airshed.

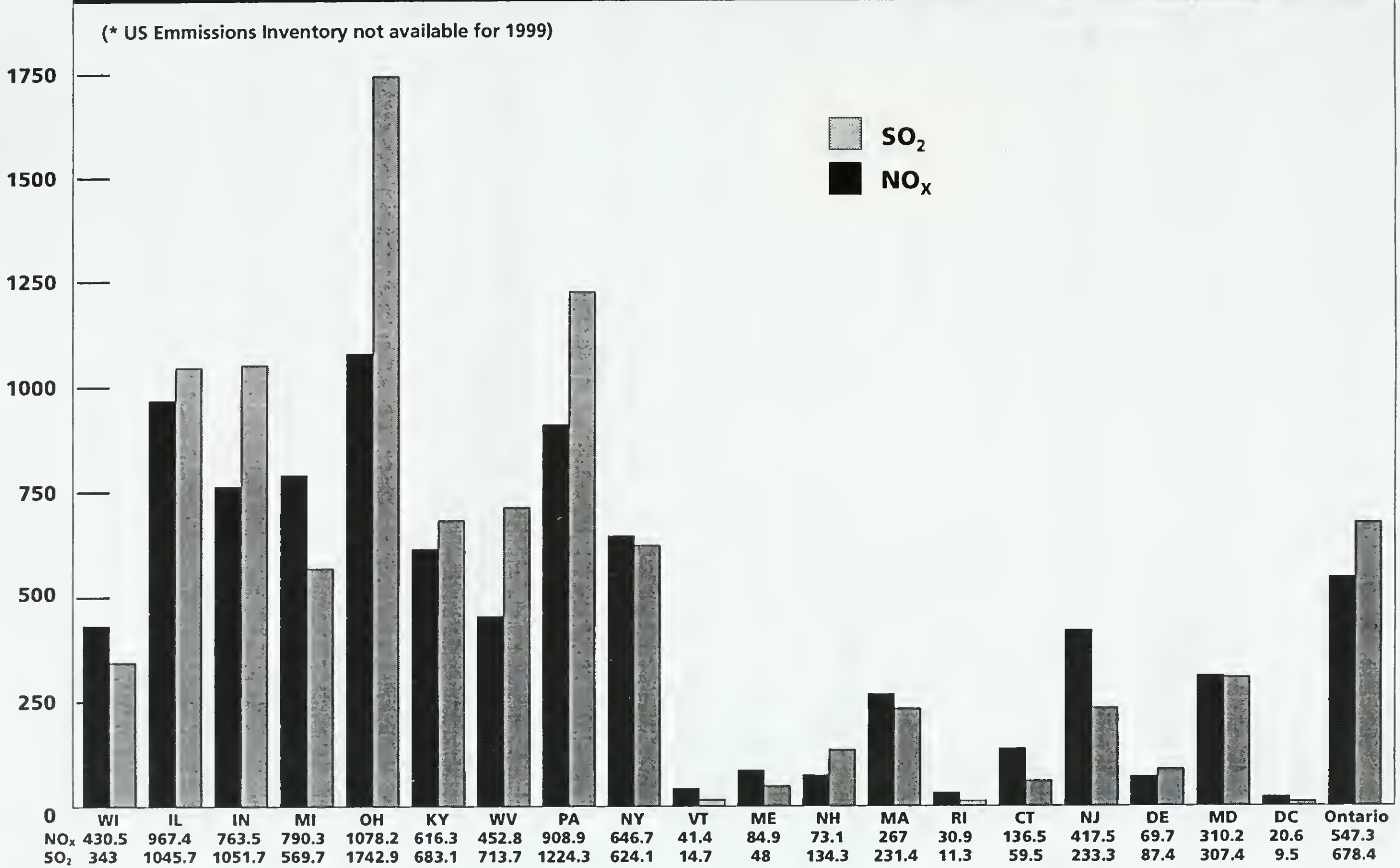
Table 4.1: PEMA Jurisdictions and Ontario 1998* Total Emissions (kilotonnes) (*1999 US Data n/a)

	Total Emissions from Jurisdiction				Electricity Sector Emissions					
State	NO_2 (kilotonnes)	NO_X Rank	SO_2 (kilotonnes)	SO_2 Rank	NO_2 (kilotonnes)	NO_2 Rank	% of State	SO_2 (kilotonnes)	SO_2 Rank	% of State
1 Wisconsin	430.5	10	343.0	10	102.8	8	24%	207.9	11	61%
2 Illinois	967.4	2	1,045.7	4	265.3	5	27%	735.3	6	70%
3 Indiana	763.5	5	1,051.7	3	331.3	3	43%	882.4	2	84%
4 Michigan	790.3	4	569.7	9	200.8	7	25%	391.3	10	69%
5 Ohio	1,078.2	1	1,742.9	1	474.1	4	44%	1,309.0	4	75%
6 Kentucky	616.3	7	683.1	6	290.5	2	47%	568.5	3	83%
7 West Virginia	452.8	9	713.7	5	265.5	1	59%	605.9	1	85%
8 Pennsylvania	908.9	3	1,224.3	2	217.1	10	24%	973.4	5	80%
9 New York	646.7	6	624.1	8	87.0	15	13%	278.5	13	45%
10 Vermont	41.4	18	14.7	18	1.0	18	2%	0.1	19	0%
11 Maine	84.9	15	48.0	17	2.6	17	3%	13.0	16	27%
12 New Hampshire	73.1	16	134.3	14	13.1	11	18%	50.2	9	37%
13 Massachusetts	267.0	13	231.4	13	42.0	14	16%	142.5	12	62%
14 Rhode Island	30.9	19	11.3	19	0.1	20	0%	0.0	20	0%
15 Connecticut	136.5	14	59.5	16	14.5	16	11%	44.0	14	74%
16 New Jersey	417.5	11	233.3	12	66.0	12	16%	56.0	17	24%
17 Delaware	69.7	17	87.4	15	13.7	9	20%	39.0	7	45%
18 Maryland	310.2	12	307.4	11	110.2	6	36%	262.4	8	85%
19 DC	20.6	20	9.5	20	0.4	19	2%	1.3	18	13%
19 State PEMA	8,106.4		9,134.9		2,498.2		31%	6,560.8		72%
Ontario	547.3	8	678.4	7	100.9	13	18%	143	11	21%

Note:

- "% of State" Column is the percentage that the electricity sector contributes to total emissions from a jurisdiction
- Rank: highest emissions are assigned a rank of "1"
- Ontario's NO_X emissions for electricity sector are comprised of 85.5 kt from OPG facilities and 15.4 kt estimated for Independent Power Producers

Figure 4.1A: 1998* Total Emissions (in kilotonnes) PEMA Jurisdictions and Ontario



On an emissions-per-unit-of-population basis (see Figure 4.1.B), compared with the 19 jurisdictions in the U.S. PEMA, Ontario is the fifteenth-largest emitter of NOx and the eleventh-largest emitter of SO_2.

West Virginia has the largest emissions per unit of population - approximately eight times Ontario's emissions for both NOx and SO_2. Again, a jurisdiction's reliance on coal for power has a strong impact on its ranking. West Virginia burns coal for more than 98 per cent of its power compared to Ontario's 24 per cent.

Due to its heavy reliance on coal to generate electricity, the U.S. electricity sector accounts for a major part of the country's total NOx and SO_2 emissions. Emissions data for 1998 indicate that electric utilities represent:

- 25 per cent of total U.S. national NOx emissions – coal combustion represents almost 90 per cent of these emissions; and
- 68 per cent of total U.S. national SO_2 emissions – coal combustion represents well over 90 per cent of these emissions.

In the 19-jurisdiction U.S. PEMA region, approximately 80 per cent of NOx emissions come from two sectors – those being electricity (30.8 per cent) and transportation (48.4 per cent).

These two sectors also account for 80 per cent of NOx emissions in Ontario. However, the mix differs considerably. Transportation in Ontario (on and off-road) accounts for 63.4 per cent of NOx, while electricity accounts for 14.7 per cent.

In the 19-jurisdiction U.S. PEMA region, approximately 86 per cent of SO_2 emissions come from two areas (1998 data); the electricity sector (72 per cent) and fuel combustion for other industrial processes (14 per cent).

In 1998, the electricity sector accounted for 21 per cent of Ontario's total provincial SO_2 emissions. Ontario's other major sources of SO_2 emissions were nickel smelting, which accounted for 43.6 per cent in 1998, petroleum refining which accounted for 9.6 per cent and other primary metals processing which accounted for 6.4 per cent.

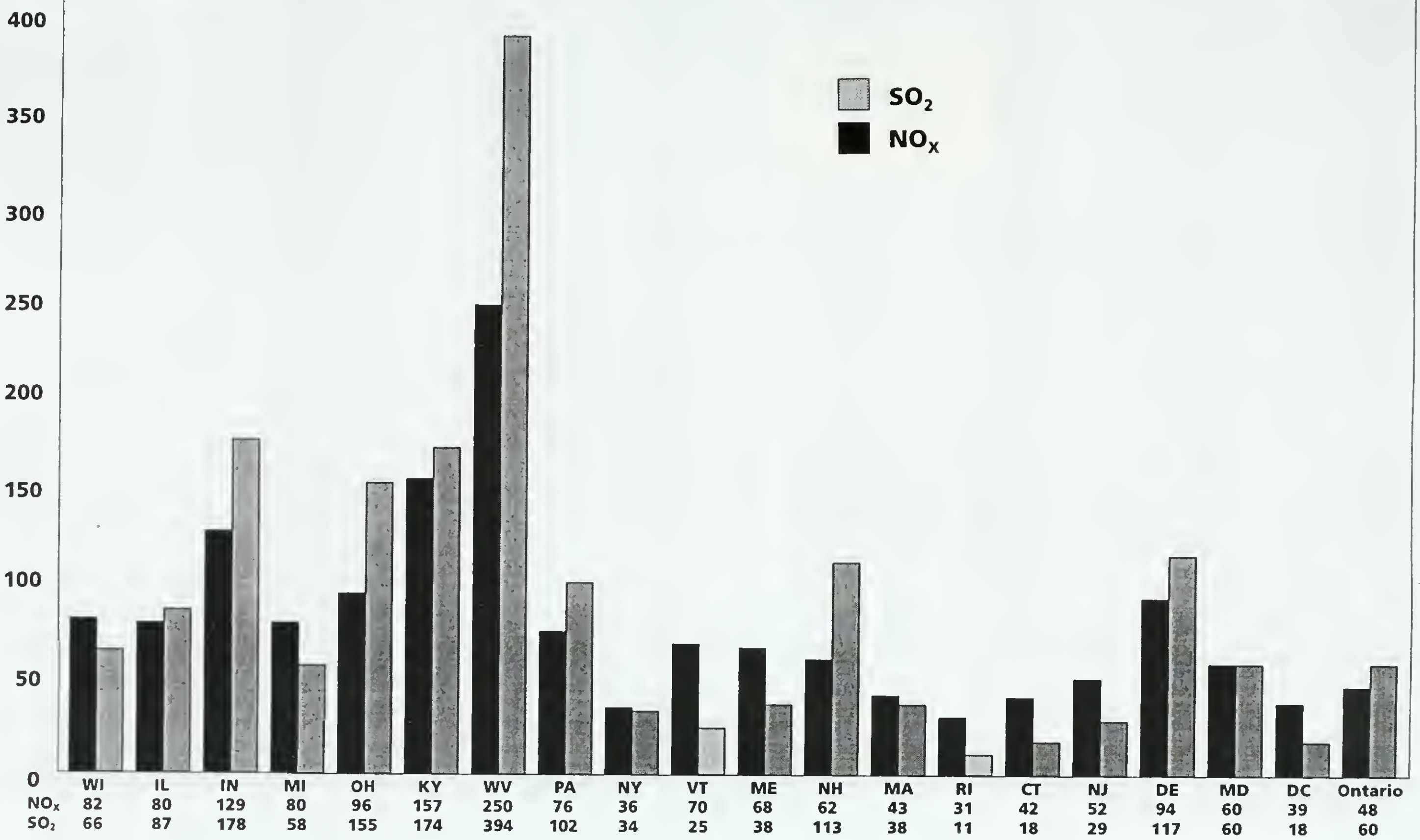
II. Total NOx and SO_2 emissions from electricity sectors

Electricity-sector emissions vary widely in different jurisdictions (see "% of state" column in Table 4.1) depending on a jurisdiction's reliance on fossil fuels to generate electricity and the type of fossil fuel burned - or 'generation mix'.

Within the U.S. PEMA, 60 per cent of electricity is produced by burning coal.

Figure 4.1B: 1998* Total Emissions per 1,000 Population PEMA Jurisdictions and Ontario (tonnes/1,000 pop.)

(* US Emmissions Inventory not available for 1999)



Generation mix

The source of electricity generation in a jurisdiction depends on a number of factors, including: the availability of water resources suitable for hydro-electric development, the capital cost and the use of nuclear power, and the cost and availability of fossil fuel power (i.e., many states such as West Virginia have extensive low-cost coal reserves).

Table 4.2 shows Ontario's generation mix and total emissions from the electricity sector, compared with the U.S. PEMA jurisdictions.

Emission rates

An emission rate is a measure of environmental performance for electricity-generating facilities. An emission rate may be specified in two ways:

- **output-based** - showing the amount of pollutant per unit of electricity produced. This rate is represented as kilograms of pollutant per Megawatt hour, or kg/MWh (see Table 4.3); and
- **input-based** - showing the amount of pollutant emitted per unit of fuel burned. This rate is represented as pounds of pollutant per million British Thermal Units of fossil fuel burned, or lb/mmBtu (see Tables 4.4 and 4.5).

Jurisdictions that rely heavily on coal have much higher emission rates than those that get their power from other, cleaner sources. In West Virginia, for example, where coal is burned to generate almost 99 per cent of electricity, the power sector accounts for 59 per cent of NOx and 85 per cent of SO_2 emissions. Accordingly, the state has very high emission rates (see Table 4.3).

Ontario, on the other hand, relies less on coal and therefore, the province's emission rates from the electricity sector are much lower. In 1999, less than 24 per cent of Ontario's generation was produced by coal, while the rest was produced by hydroelectric and nuclear power, which produce no significant air pollution. As a result, Ontario's electricity sector accounted for approximately 17.6 per cent of NOx and 23.7 per cent of SO_2 emissions across the province.

Electricity sector average emission rates

Table 4.3 and Figure 4.3 provide a comparison between estimated average rates from the entire electricity sectors in the U.S. PEMA jurisdictions and Ontario. The U.S. emission rates are estimated from emissions reported to the U.S. EPA's Acid Rain Program (for units larger than 25 MW) and electricity generation data reported to the U.S. Electricity Information Administration. Across jurisdictions, there are significant differences in emissions per unit of electricity generated. These variations reflect the level of investment in non-emitting sources of electricity - like hydroelectric and nuclear - and the level of investment in technologies that lower emissions from the fossil fuel electricity sector in each jurisdiction.

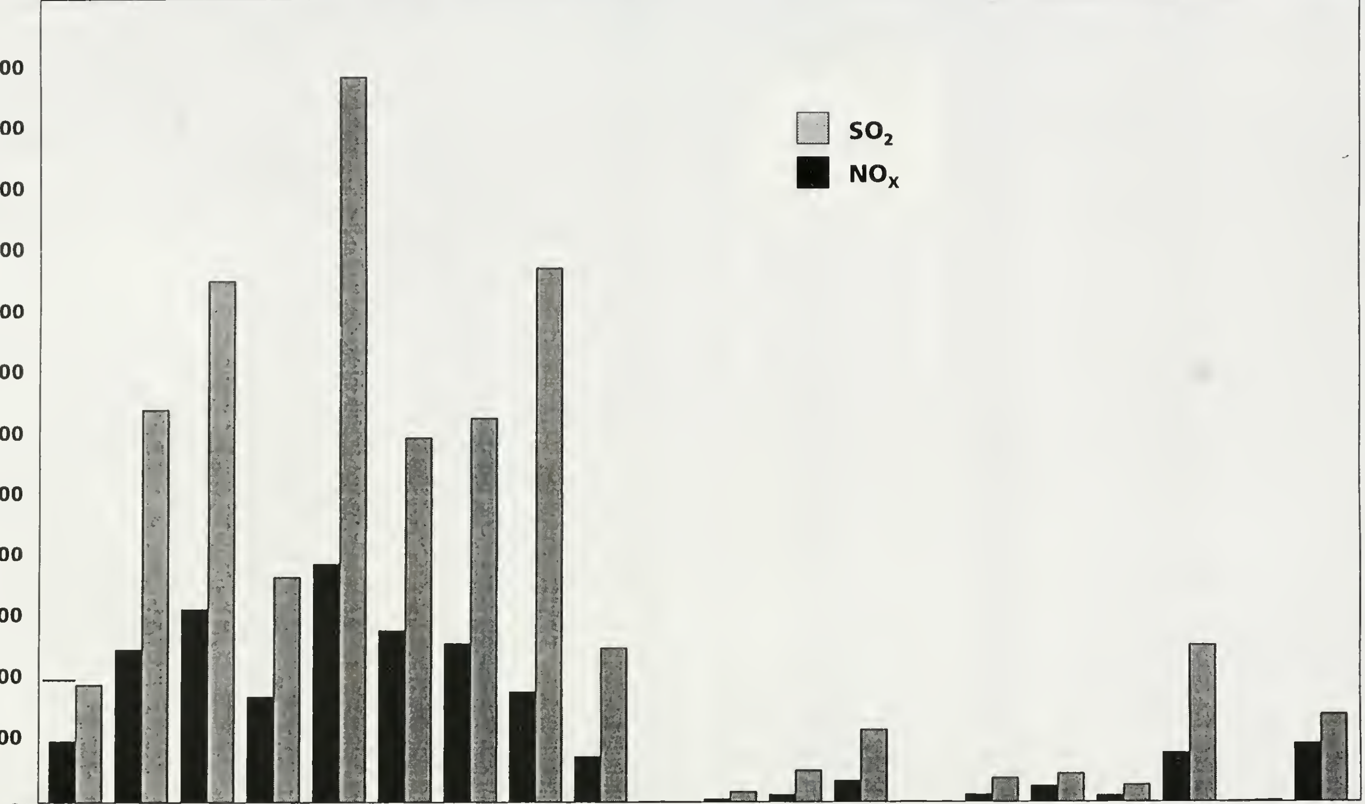
Table 4.2: Electricity Generation Mix - 1999 Net Electric Generation by Source (GWh)

State	Coal	%	Petrol.	%	Gas	%	Nuclear	%	Hydro	%	Other	%	Total
1 Wisconsin	41,157	69.4%	920	1.6%	1,975	3.3%	11,495	19.4%	1,917	3.2%	1,798	3.0%	59,262
2 Illinois	75,245	46.1%	464	0.3%	4,891	3.0%	81,737	50.1%	128	0.1%	759	0.5%	163,224
3 Indiana	114,706	94.2%	1,016	0.8%	5,573	4.6%	0	0.0%	407	0.3%	131	0.1%	121,833
4 Michigan	70,596	68.1%	1,437	1.4%	13,507	13.0%	14,591	14.1%	545	0.5%	2,979	2.9%	103,655
5 Ohio	123,294	86.5%	490	0.3%	1,108	0.8%	16,422	11.5%	423	0.3%	841	0.6%	142,578
6 Kentucky	88,915	96.0%	685	0.7%	458	0.5%	0	0.0%	2,557	2.8%	19	0.0%	92,634
7 West Virginia	93,295	98.6%	187	0.2%	240	0.3%	0	0.0%	920	1.0%	0	0.0%	94,642
8 Pennsylvania	111,010	57.1%	3,693	1.9%	4,472	2.3%	71,123	36.6%	1,454	0.7%	2,733	1.4%	194,485
9 New York	22,956	15.8%	13,387	9.2%	47,273	32.6%	37,019	25.5%	21,432	14.8%	3,003	2.1%	145,070
10 Vermont	0	0.0%	23	0.4%	18	0.3%	4,059	72.5%	1,065	19.0%	437	7.8%	5,602
11 Maine	977	8.2%	4,288	35.9%	21	0.2%	0	0.0%	2,610	21.9%	4,046	33.9%	11,942
12 New Hampshire	3,328	20.4%	1,583	9.7%	48	0.3%	8,676	53.1%	1,390	8.5%	1,304	8.0%	16,329
13 Massachusetts	11,280	28.5%	10,485	26.5%	10,811	27.3%	4,473	11.3%	483	1.2%	2,068	5.2%	39,600
14 Rhode Island	0	0.0%	393	5.8%	6,259	92.4%	0	0.0%	7	0.1%	118	1.7%	6,777
15 Connecticut	2,081	7.5%	8,001	28.7%	2,577	9.2%	12,675	45.4%	422	1.5%	2,145	7.7%	27,901
16 New Jersey	8,002	14.0%	861	1.5%	17,926	31.5%	28,971	50.9%	-128	-0.2%	1,334	2.3%	56,966
17 Delaware	2,867	42.0%	1,496	21.9%	2,452	36.0%	0	0.0%	0	0.0%	4	0.1%	6,819
18 Maryland	29,683	57.0%	4,048	7.8%	2,549	4.9%	13,312	25.6%	1,422	2.7%	1,044	2.0%	52,058
19 District of Columbia	0	0.0%	230	100.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	230
20 U.S. PEMA	799,392	59.6%	53,687	4.0%	122,158	9.1%	304,553	22.7%	37,054	2.8%	24,763	1.8%	1,341,607
Ontario	**Coal**	**%**	**Petrol.**	**%**	**Gas**	**%**	**Nuclear**	**%**	**Hydro**	**%**	**Other**	**%**	**Total**
Ontario Power Gen.	34,068	25.9%	598	0.5%	1,795	1.4%	61,400	46.7%	33,600	25.6%	0	0.0%	131,500
Independent Power	0	0.0%	0	0.0%	10,450	89.8%	0	0.0%	621	5.3%	565	4.9%	11,636
Ontario (OPG+IPPs)	34,068	23.8%	598	0.4%	12,245	8.6%	61,400	42.9%	34,221	23.9%	565	0.4%	143,136

Note:

- U.S. data is from Energy Information Administration Electric Power Annual 1999, Volume I, August 2000.
- U.S. data includes generation from utility and non-utility sources. Data for non-utility portion is preliminary.
- Ontario IPPs are Independent Power Producers. OPG is generation by Ontario Power Generation.
- U.S. PEMA is the American portion of the Pollution Emission Management Area set in the Ozone Annex between Canada and the U.S. signed December 7, 2000.
- The U.S. portion of the PEMA includes 19 U.S. jurisdictions listed above (18 states and the District of Columbia)
- GWh is approximately equal to the electricity used by 80 homes in one year.

Figure 4.2: Electricity Sector —1999 Total Emmissions NO_X and SO_2 (kilotonnes)



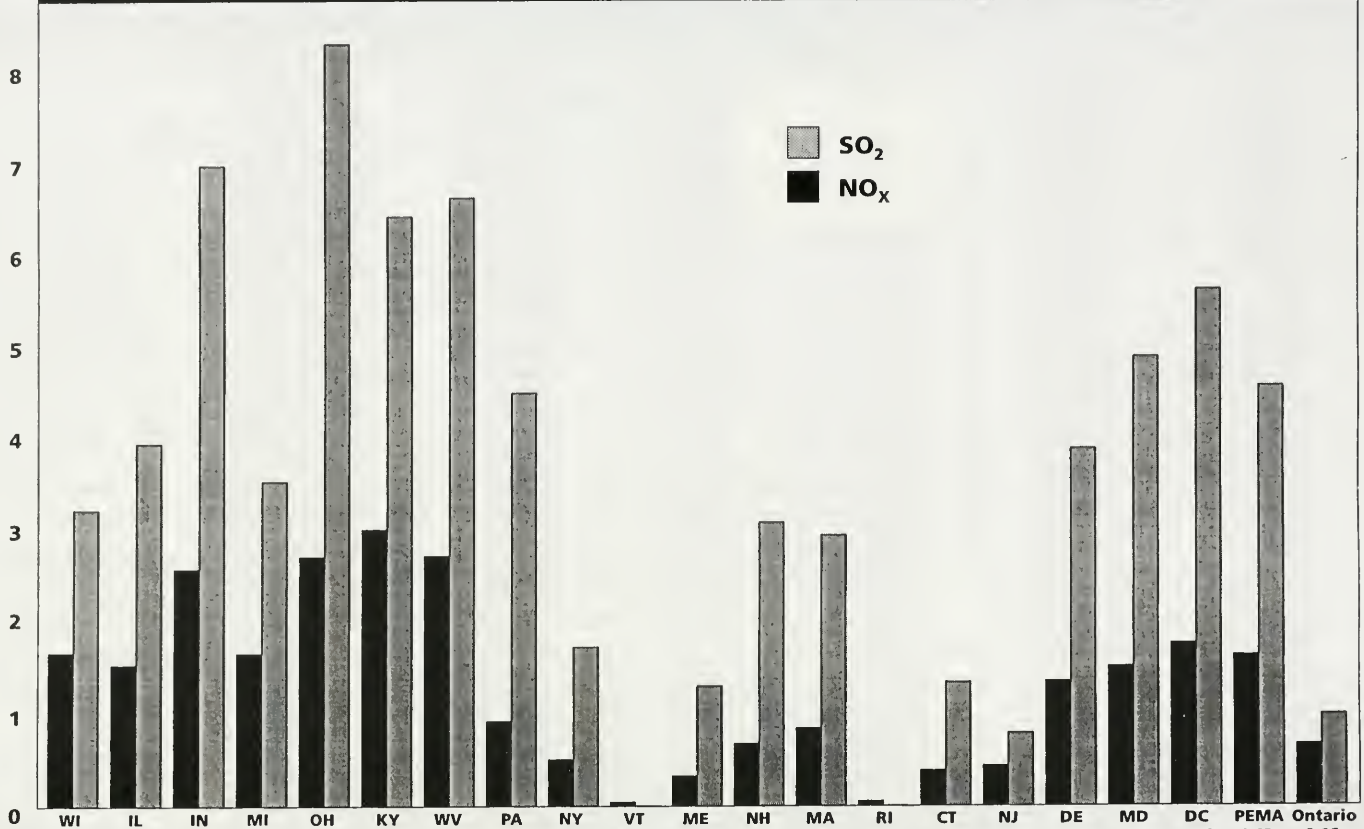
	WI	IL	IN	MI	OH	KY	WV	PA	NY	VT	ME	NH	MA	RI	CT	NJ	DE	MD	DC	Ontario
NO_X	98.9	249.1	315.2	171.6	388.2	279.7	258.6	179.6	73.2	0.2	3.8	11	33.2	0.3	10.7	24.6	9.2	78.6	0.4	94.1
SO_2	191.7	644.3	854.4	367.1	1188.1	597.8	630.1	874.7	250.7	0	15.6	50.5	116.7	0	37.4	44.9	26.5	255.6	1.3	142.1

Table 4.3: Electricity Sector Estimated 1999 Fleet Average Emission Rates - SO_2, NO_X, CO_2

	State	Importer/ Exporter	Primary Fuel	Generation (GWh)	Emissions NO_2 (kilotonnes)	Emissions SO_2 (kilotonnes)	Emissions CO_2 (kilotonnes)	Emission Rates NO_2 (kg/MWh)	Rank	Emission Rates SO_2 (kg/MWh)	Rank	Emission Rates CO_2 (kg/MWh)	Rank
1	Wisconsin	Importer	Coal	59,262	98.9	191.7	46,677.8	1.67	6	3.23	11	787.65	6
2	Illinois	Exporter	Coal	163,224	249.1	644.3	81,520.9	1.53	8	3.95	9	499.44	11
3	Indiana	Exporter	Coal	121,833	315.2	854.4	125,731.2	2.59	4	7.01	2	1,032.00	2
4	Michigan	Importer	Coal	103,655	171.6	367.1	72,716.6	1.66	7	3.54	10	701.53	7
5	Ohio	Importer	Coal	142,578	388.2	1,188.1	121,439.3	2.72	3	8.33	1	851.74	5
6	Kentucky	Exporter	Coal	92,634	279.7	597.8	94,933.8	3.02	1	6.45	4	1,024.83	3
7	West Virginia	Exporter	Coal	94,642	258.6	630.1	85,390.6	2.73	2	6.66	3	902.25	4
8	Pennsylvania	Exporter	Coal	194,485	179.6	874.7	96,870.0	0.92	11	4.50	7	498.08	12
9	New York	Importer	Nuclear	145,070	73.2	250.7	53,076.9	0.50	15	1.73	14	365.87	13
10	Vermont	Exporter	Nuclear	5,602	0.2	0.0	290.3	0.04	20	0.00	20	51.82	20
11	Maine	Importer	Petroleum	11,942	3.8	15.6	2,225.4	0.32	18	1.30	16	186.35	17
12	New Hampshire	Exporter	Nuclear	16,329	11.0	50.5	5,060.5	0.67	13	3.09	12	309.91	14
13	Massachusetts	Importer	Coal	39,600	33.2	116.7	21,893.7	0.84	12	2.95	13	552.87	10
14	Rhode Island	Importer	Petroleum	6,777	0.3	0.0	1,180.4	0.05	19	0.00	19	174.18	18
15	Connecticut	Importer	Petroleum	27,901	10.7	37.4	8,612.4	0.38	17	1.34	15	308.68	15
16	New Jersey	Importer	Nuclear	56,966	24.6	44.9	9,638.2	0.43	16	0.79	18	169.19	19
17	Delaware	Importer	Coal	6,819	9.2	26.5	4,779.3	1.35	10	3.89	8	700.89	8
18	Maryland	Importer	Coal	52,058	78.6	255.6	33,457.2	1.51	9	4.91	6	642.69	9
19	District of Columbia	Importer	Petroleum	230	0.4	1.3	242.6	1.76	5	5.65	5	1,054.84	1
	U.S. PEMA			1,341,607	2,186.1	6,147.2	865,737.1	1.63		4.58		645.30	
	Ontario	Exporter	Nuclear	143,136	94.1	142.1	37,203.7	0.66	14	0.99	17	259.9	16

Note:
- U.S. Emission Data is from U.S. EPA Acid Rain Database (Includes All Facilities Regulated Under U.S. Acid Rain Program)
- U.S. Generation is from U.S. Energy Information Administration Monthly Reports
- Ontario Data Includes OPG plus 11,636 GWh from Independent Power Producers. Emissions from IPPs are estimated.
- Rank: highest emission rates are assigned a rank of "1"

Figure 4.3: Electricity Sector 1999 Estimated Fleet Average— NO_X and SO_2 Emission Rates (kg/MWh)



	WI	IL	IN	MI	OH	KY	WV	PA	NY	VT	ME	NH	MA	RI	CT	NJ	DE	MD	DC	PEMA	Ontario
NO_X	1.67	1.53	2.59	1.66	2.72	3.02	2.73	0.92	0.5	0.04	0.32	0.67	0.84	0.05	0.38	0.43	1.35	1.51	1.76	1.63	0.66
SO_2	3.23	3.95	7.01	3.54	8.33	6.45	6.66	4.5	1.73	0	1.3	3.09	2.95	0	1.34	0.79	3.89	4.91	5.65	4.58	0.99

Table 4.4: All Fossil Units - 1999 U.S. Jurisdictions/Ontario Summary - SO_2,NO_x,CO_2,Fuel Burned

State	Fossil Fuel Burned (mmBtu)	Emissions NO_2 (kilotonnes)	Emissions SO_2 (kilotonnes)	Emissions CO_2 (kilotonnes)	Emission Rates NO_2 (lb/mmBTU)	Rank	SO_2 (lb/mmBTU)	Rank	CO_2 (lb/mmBTU)
1 Wisconsin	508,092,322	98.9	191.7	46,677.8	0.43	10	0.83	16	203
2 Illinois	895,595,543	249.1	644.3	81,520.9	0.61	3	1.59	4	201
3 Indiana	1,350,676,762	315.2	854.4	125,731.2	0.51	5	1.39	7	205
4 Michigan	803,099,194	171.6	367.1	72,716.6	0.47	8	1.01	10	200
5 Ohio	1,306,854,953	388.2	1,188.1	121,439.3	0.65	1	2.00	1	205
6 Kentucky	1,020,879,508	279.7	597.8	94,933.8	0.60	4	1.29	8	205
7 West Virginia	917,416,842	258.6	630.1	85,390.6	0.62	2	1.51	5	205
8 Pennsylvania	1,051,296,286	179.6	874.7	96,870.0	0.38	12	1.83	3	203
9 New York	713,705,400	73.2	250.7	53,076.9	0.23	17	0.77	17	164
10 Vermont	3,177,517	0.2	0.0	290.3	0.16	19	0.00	20	201
11 Maine	30,330,453	3.8	15.6	2,225.4	0.28	14	1.13	9	162
12 New Hampshire	58,812,361	11.0	50.5	5,060.5	0.41	11	1.89	2	190
13 Massachusetts	270,559,192	33.2	116.7	21,893.7	0.27	16	0.95	12	178
14 Rhode Island	21,929,985	0.3	0.0	1,180.4	0.03	20	0.00	19	119
15 Connecticut	123,767,311	10.7	37.4	8,612.4	0.19	18	0.67	18	153
16 New Jersey	106,503,621	24.6	44.9	9,638.2	0.51	6	0.93	13	200
17 Delaware	58,793,492	9.2	26.5	4,779.3	0.34	13	0.99	11	179
18 Maryland	379,951,954	78.6	255.6	33,457.2	0.46	9	1.48	6	194
19 District of Columbia	3,304,107	0.4	1.3	242.6	0.27	15	0.87	15	162
U.S. PEMA	9,624,746,803	2,186.1	6,147.2	865,737.1	0.50		1.41		198
Ontario (OPG)	353,896,214	78.8	142.1	32,092.0	0.49	7	0.89	14	200
Ontario (OPG+IPPs)	N.A.	94.1	142.1	37,203.7	N.A.		N.A.		N.A.

Note:
- U.S. Emission Data is from U.S. EPA Acid Rain Database (Includes All Facilities Regulated Under U.S. Acid Rain Program)
- Fuel Use of Ontario Independent Power Producers is Not Available. Total Emissions from IPPs are Estimated.
- Rank: highest emission rates are assigned a rank of "1"

Figure 4.4: Electricity Sector—All Fossil Stations 1999 Average NO_X and SO_2 Emission Rates (lb/mBTU)

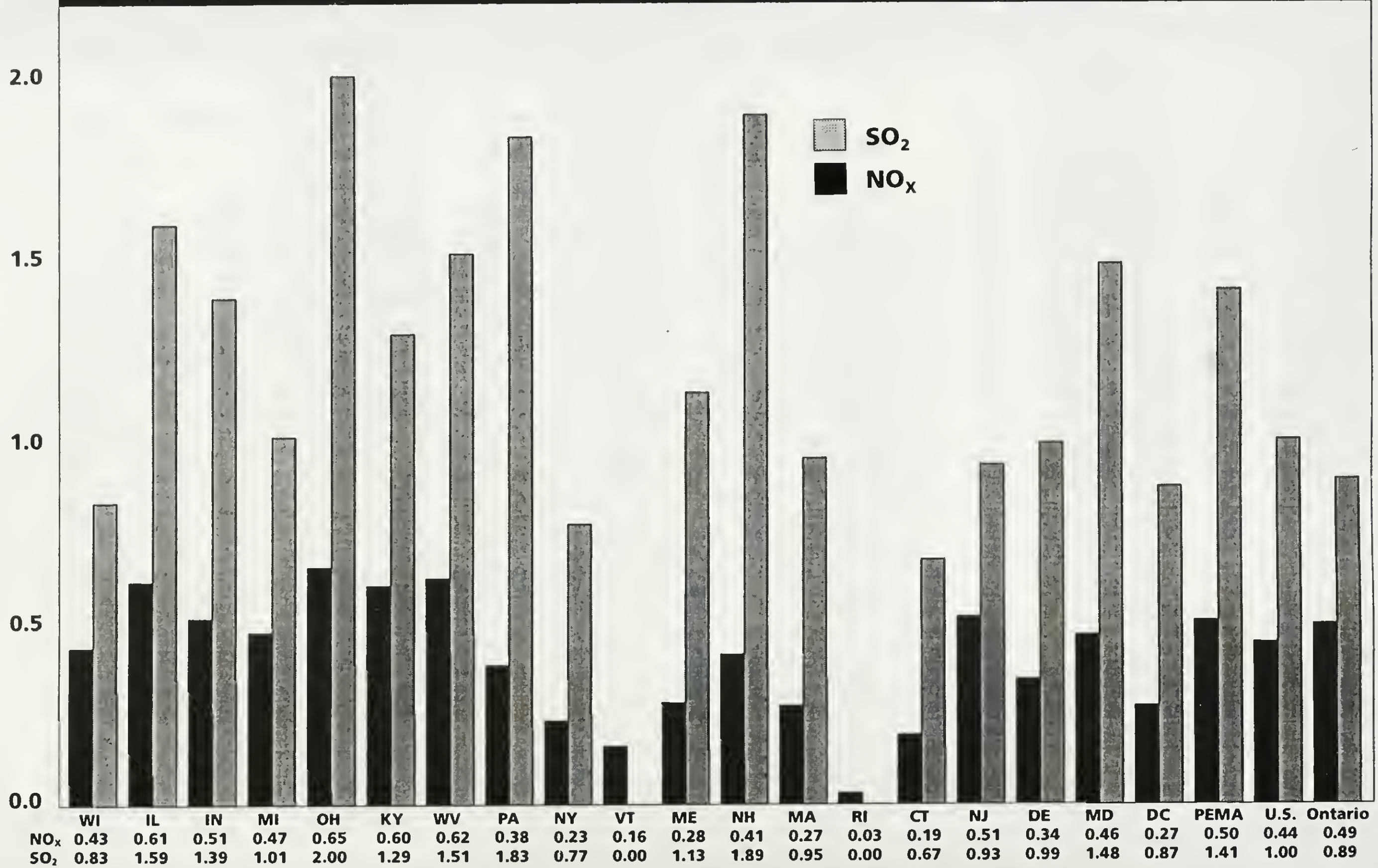


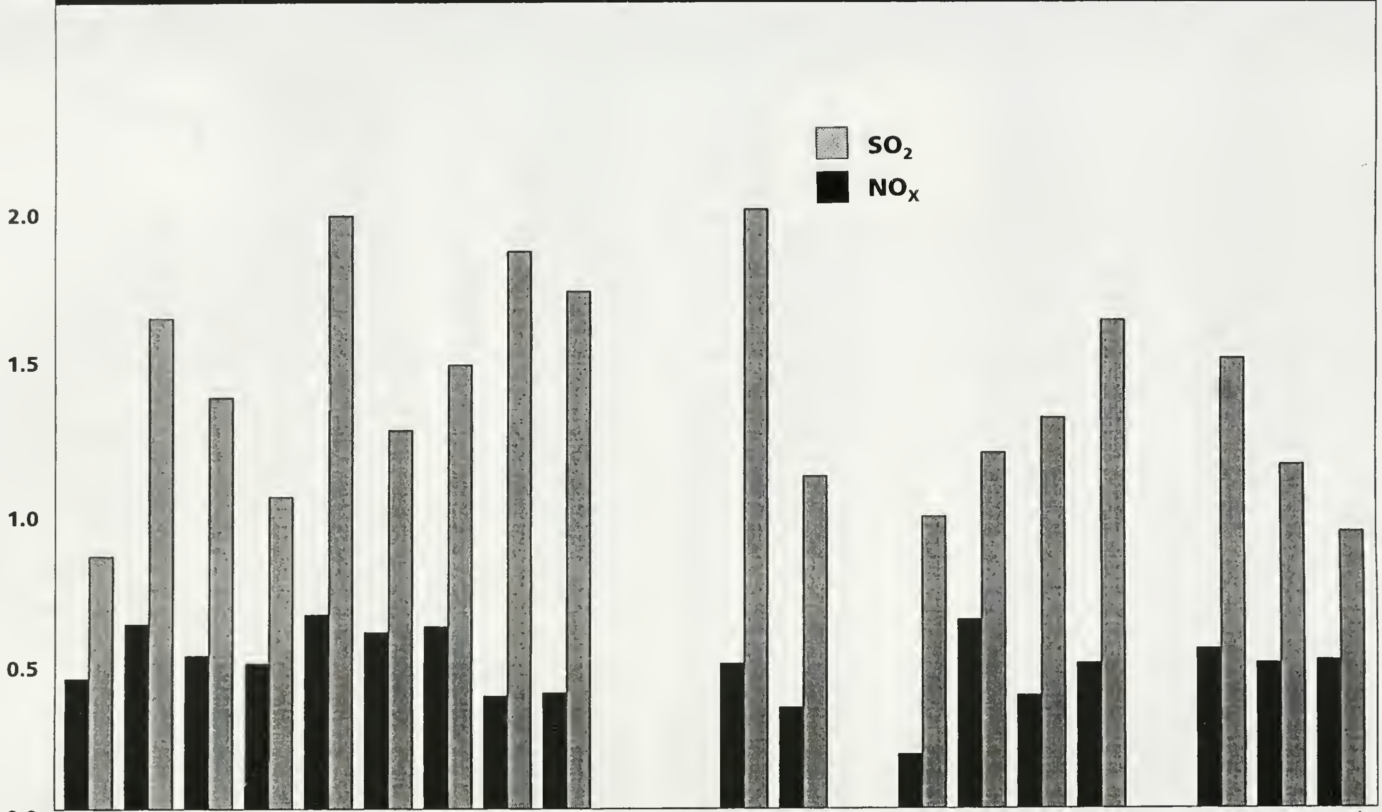
Table 4.5: Coal Fired Units - 1999 State Summary of SO_2, NO_x, CO_2, and Coal Burned

		Emissions			Emission Rates					
State	Coal Burned (mmBTU)	NO_2 (kilotonnes)	SO_2 (kilotonnes)	CO_2 (kilotonnes)	NO_2 (lb/mmBTU)	NO_2 Rank	SO_2 (lb/mmBTU)	SO_2 Rank	CO_2 (lb/mmBTU)	CO_2 Rank
1 Wisconsin	492,957,654	98.1	191.7	45,854.8	0.44	11	0.86	16	205	7
2 Illinois	850,001,535	243.7	643.3	78,998.6	0.63	3	1.67	5	205	10
3 Indiana	1,340,217,175	314.4	853.9	124,679.1	0.52	6	1.40	8	205	6
4 Michigan	747,647,562	166.7	360.4	69,770.6	0.49	8	1.06	13	206	2
5 Ohio	1,298,440,004	387.5	1,188.0	120,974.8	0.66	1	2.02	2	205	3
6 Kentucky	1,018,788,644	279.3	597.8	94,821.2	0.60	5	1.29	10	205	5
7 West Virginia	917,416,842	258.6	630.1	85,390.6	0.62	4	1.51	7	205	4
8 Pennsylvania	1,007,886,640	175.5	866.8	94,081.8	0.38	13	1.90	3	206	1
9 New York	239,236,092	42.2	191.1	22,076.9	0.39	12	1.76	4	203	13
10 Vermont	0	0.0	0.0	0.0	0.00	17	0.00	17	0	17
11 Maine	0	0.0	0.0	0.0	0.00	18	0.00	18	0	18
12 New Hampshire	39,450,857	8.8	36.4	3,645.9	0.49	10	2.04	1	204	11
13 Massachusetts	119,674,321	18.3	61.5	11,131.0	0.34	15	1.13	12	205	8
14 Rhode Island	0	0.0	0.0	0.0	0.00	19	0.00	19	0	19
15 Connecticut	17,378,829	1.4	7.8	1,277.2	0.18	16	0.99	14	162	16
16 New Jersey	79,138,468	23.1	43.4	7,104.9	0.64	2	1.21	11	198	15
17 Delaware	37,324,657	6.4	22.5	3,363.8	0.38	14	1.33	9	199	14
18 Maryland	311,478,673	69.3	234.2	28,952.6	0.49	9	1.66	6	205	9
19 District of Columbia	0	0.0	0.0	0.0	0.00	20	0.00	20	0	20
U.S. PEMA	8,517,037,953	2,093.1	5,928.9	792,123.8	0.54		1.53		205	
Ontario	330,276,819	75.5	140.4	30,509.0	0.50	7	0.94	15	204	12

Note:

- U.S. Emission Data is from U.S. EPA Acid Rain Database (Includes All Facilities Regulated Under U.S. Acid Rain Program)
- Rank: highest emission rates are assigned a rank of "1'
- A unit is defined as coal fired if 50% or more of its fuel consumption is coal

Figure 4.5: Coal Stations — 1999 Average NO_x and SO_2 Emission Rates (lb/mBTU)



	WI	IL	IN	MI	OH	KY	WV	PA	NY	VT	ME	NH	MA	RI	CT	NJ	DE	MD	DC	PEMA	U.S.	Ontario
NO_x	0.44	0.63	0.52	0.49	0.66	0.6	0.62	0.38	0.39	0	0	0.49	0.34	0	0.18	0.64	0.38	0.49	0	0.54	0.49	0.50
SO_2	0.86	1.67	1.4	1.06	2.02	1.29	1.51	1.9	1.76	0	0	2.04	1.13	0	0.99	1.21	1.33	1.66	0	1.53	1.17	0.94

III. Total NOx and SO_2 emissions from fossil fuel generated electricity

Fossil fuel stations burn coal, oil or gas.

The average 1999 NOx and SO_2 emission rates from Ontario Power Generation's (OPG's) six fossil fuel facilities (5 coal and 1 oil/gas) were:

- NOx: 0.49 lb of NO_2/mmBtu; and
- SO_2: 0.89 lb of SO_2/mmBtu.

Table 4.4 and Figure 4.4 provide comparisons of average 1999 emission rates for fossil fuel units within Ontario and the 19 PEMA jurisdictions. The average emission rates in the PEMA region were:

- NOx: 0.5 lb of NO_2/mmBtu; and
- SO_2: 1.41 lb of SO_2/mmBtu.

Six jurisdictions had average fossil fuel station NOx emission rates higher than OPG's, while 13 jurisdictions had average fossil fuel station SO_2 emission rates higher than OPG's.

IV. Total NOx and SO_2 emissions from coal-fired electricity

Table 4.5 and Figure 4.5 provide comparisons of average 1999 emission rates for coal stations in the 19 PEMA jurisdictions. The average emission rates were:

- NOx: 0.54 lb of NO_2/mmBtu; and
- SO_2: 1.53 lb of SO_2/mmBtu.

Six jurisdictions had average coal station NOx emission rates higher than OPG's, while 14 had average coal station SO_2 emission rates higher than OPG's. Four jurisdictions within the PEMA - Vermont, Maine, Rhode Island and the District of Columbia - did not burn coal in 1999.

Emission control programs in the United States

Environmental limits in neighbouring jurisdictions are an important consideration when setting requirements in Ontario. In a competitive electricity market, in which imports and exports of electric power are expected to increase, differing levels of environmental standards may affect competitiveness. If electricity imported into Ontario is produced by generators operating under lesser environmental standards, Ontario's efforts to improve air quality will be undermined. Further, the competitiveness of Ontario's electricity sector would be disadvantaged if limits were

less onerous in other markets.

The regional transport of pollutants is a major problem in Ontario and the northeastern U.S. Northeastern states are taking action to reduce NOx emissions and improve their air quality. At the same time, they are calling on midwestern states to do more to lower their air emissions.

More than 50 per cent of Ontario's ground-level ozone (smog) problem is due to emissions that are imported from the U.S. The electricity sectors in the midwest are predominantly coal-fired and account for a large portion of their total state emissions. More stringent limits on midwest state electricity sectors would translate into significant benefits for air quality in Ontario and the northeastern U.S.

Table 4.6 on the following page provides a summary of U.S. EPA programs and state-specific programs within the northeastern U.S.

Table 4.6: Selected U.S. electricity sector air emission programs		
Program	**Program Characteristics**	**Expected Benefits**
U.S. EPA Acid Rain (SO_2) Program **(Regulated SO_2 Emission Caps)**	**Regulated SO_2 emission caps -** represents EPA minimum requirement for SO_2 emissions. A few states have more stringent requirements. **Nationwide cap and trade program -** for electricity sector. **Emissions allowances -** allocated to electricity utilities based on a formula - each allowance gives a utility the right to emit one tonne of SO_2. At the end of the year, each utility must surrender emission allowances to match its actual emissions for that year. Utilities can bank unused emission allowances for use in a future year. **Two phases of limits have been implemented -** Phase I began January 1, 1995, and covered only the largest, highest-emitting boilers. Phase II began January 1, 2000. The Phase II limit is more stringent and covers all fossil fuel generating units greater than 25 MW in capacity.	• 1999 emissions were 28 per cent below 1980 levels (for all units >25 MW). • The cap for 2000 is set at 46.9 per cent below 1980 levels; however, a significant quantity of allowances have been banked from Phase I. • The cap will be reduced to 49.7 per cent below 1980 levels in 2010.
U.S. EPA Acid Rain (NOx) Program **(Regulated NOx Emission Rates)**	**Nationwide annual NOx emission performance standards -** represents EPA minimum requirement for coal-fired generating units greater than 25 MW in capacity. Some states have implemented more stringent limits.	• In 1999, the average NOx emission rate for coal-fired units covered by requirements within the U.S. PEMA was 0.54 lb/mmBtu.
U.S. EPA NOx SIP Call - States are required to develop and implement regulations to begin May 1, 2004.	**Seasonal NOx caps -** for summer ozone season (five months: May to Sept.) - slated to begin May 2004 and come into full effect May 1, 2007. The other seven months of the year are not capped. Limits will apply to 22 jurisdictions: District of Columbia, Alabama, Connecticut, Delaware, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia and to parts of Georgia and Missouri. **Electricity sector -** approximately 84 per cent of the NOx reductions are expected to come from the electricity sector. However, states may propose alternatives. Nitrogen oxides caps for the electricity sector were calculated by multiplying the fossil fuel use forecast for the year 2007 by an emissions performance of 0.15 lb of NO_2 per mmBtu (approx. 0.45 kg NO/MWh).	• See expected benefits below.

Program	Program Characteristics	Expected Benefits
U.S. EPA NOx SIP Call - States are required to develop and implement regulations to begin May 1, 2004. - Continued -	**Emission performance standards -** same emissions rates as the U.S. EPA Acid Rain (NOx) Program will apply during the non-ozone season (seven months - Oct. to April) unless more stringent state limits are required. **Emissions trading system -** has been proposed by the EPA and would allow trading throughout the SIP Call region and banking of allowances. **State Implementation Plans (SIPs) -** states must submit SIPs to the EPA for approval indicating how they will meet the NOx caps.	• If states cap electricity sectors at the level recommended by the EPA, electricity sector NOx emissions in the SIP Call area will be reduced 75 per cent from 1990 levels during the ozone season and approximately 50 per cent on an annual basis. • Reductions will vary from state to state.
Ozone Transport Commission (OTC) NOx Caps (State-regulated NOx emission caps)	**Ozone season NOx emission caps -** for electricity sector and large boilers in 10 northeastern U.S. jurisdictions: Connecticut, Delaware, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and the District of Columbia. **Two phases of NOx caps -** first phase began May 1, 1999. More stringent second phase begins May 1, 2003. **Emissions trading system -** allows trading throughout the OTC region and banking of allowances. **Electricity sector -** majority of reductions come from electricity sector.	• As of 1999, electricity section NOx emissions were approximately 50 per cent below 1990 ozone season levels. • Future reductions expected to match those of the NOx SIP Call - approximately 75 per cent below 1990 ozone season levels. • Reductions vary from state to state.
Mercury - **under development**	**Standard-setting process -** the U.S. EPA is in the midst of a standard-setting process for mercury emissions from coal-fired utilities. The timetable is set as follows: • a proposed limit by 2003; • limit finalized by 2004; and • limit implemented in 2007.	• Reductions from coal-fired units are expected to be between 50 and 90 per cent.
Eastern Canadian Premiers and New England Governors	**Commitment on NOx, SO_2 and mercury reductions** - Eastern Canadian Premiers and New England Governors have agreed to work together to reduce emissions of NOx, SO_2 and mercury.	• Agreed to reductions of SO_2 by 50 per cent below Clean Air Act Phase II Acid Rain requirements by 2010. • Committed to year-round limit by 2007. • Agreed to seek a 60 to 90 per cent reduction from 1995 levels from power plants by 2010.

Program	Program Characteristics	Expected Benefits
Massachusetts - **proposed regulation** to limit emissions of NOx, SO_2 and CO_2	**Proposed regulation -** to set tougher year-round output-based emission rate limits - both annual and monthly - for six facilities coined "the dirty six". **Intra-facility averaging and intra-facility trading is** to be permitted provided each facility reduces emissions by a minimum of 35 per cent below the average of 1997, 1998 and 1999 levels. **U.S. EPA SO_2 program -** facilities must also retire allowances needed under the U.S. EPA SO_2 program. **Mercury study -** commitment to complete study of mercury by December, 2002, and propose a standard.	• Proposed seven per cent CO_2 reduction from the six facilities below 1990 levels. • Proposed 50 per cent NOx and SO_2 reductions from facilities below historical emissions (1997, 1998, 1999). • Proposed Year-round NOx limits.
Connecticut - **regulation** to limit NOx and SO_2 emissions	**NOx and SO_2 limits -** two-phased regulation to toughen input based emission rate limits for NOx and SO_2 - approved December, 2000 - tentatively scheduled to begin January, 2002. **Intra-facility averaging and intra-facility trading -** to be permitted for both NOx and SO_2. **U.S. EPA SO_2 program -** facilities must also retire allowances needed under the U.S. EPA SO_2 program.	• Phase I expected to reduce SO_2 emissions by 18,893 tons per year (based on 1999 emissions) as of January, 2002. • Phase II expected to further reduce SO_2 emissions at the local level by 8,900 tons per year (based on 1999 emissions), as of January, 2003. • NOx limits expected to reduce annual NOx emissions by 3,483 tons per year - a 20 to 30 per cent reduction (based on 1999 emissions).
New York State - **proposed regulation** to reduce NOx and SO_2	**Proposed regulation -** to implement year-round NOx caps by 2003, and reduce SO_2 by 50 per cent beyond U.S. EPA requirements - to be phased in between 2003 and 2007.	• Requirements are under development. • Expectations are that New York will extend the U.S. EPA's NOx SIP Call to a year-round cap.

Program	Program Characteristics	Expected Benefits
New Hampshire - **proposed New Hampshire Clean Power Strategy** to reduce NOx, SO_2, mercury and CO_2	**Proposed regulations -** to reduce emissions of SO_2, NOx, mercury and CO_2 from New Hampshire's power plants by 2006. **The strategy proposes:** • an annual SO_2 emissions cap of 7,289 short tons (based on 1999 levels) • an annual NOx emissions cap of 3,644 short tons (based on 1999 levels) • an annual mercury emissions cap of 82 pounds; and • an annual CO_2 emissions cap of 5,046,055 short tons (based on 1990 levels). **Trading and banking of emission reductions -** under a strictly controlled and monitored overall emissions cap. **Intra-facility averaging and unit averaging -** to be permitted for SO_2, NOx and CO_2.	• Proposed 75 per cent reduction in annual SO_2 emissions. • Proposed 70 per cent reduction in annual NOx emissions from 1999 levels. • Proposed 75 per cent reduction in mercury emissions from coal-burning plants compared to 1996/97 emissions. • Proposed seven per cent CO_2 reduction from 1990 levels.

CHAPTER 5

Environmental Controls for Fossil Fuel Power Generation in Ontario

Current and Proposed

5. ENVIRONMENTAL CONTROLS FOR FOSSIL FUEL POWER GENERATION IN ONTARIO – CURRENT AND PROPOSED

Current environmental controls

Regulation 346 and Certificates of Approval

Regulation 346 under the Environmental Protection Act is the general regulation covering air pollution in Ontario. The regulation is used by the Ministry of the Environment for limiting emissions from any facility to ensure protection of the local environment.

Regulation 346 requires that any facility emitting an air contaminant not exceed Point Of Impingement (POI) limits. The POI is defined as any point in the natural environment at which the highest emissions concentration from a facility is expected to occur. In most cases, this point is found at the emitting facility's property line. All of Ontario's coal-fired power plants are subject to POI limits.

When emitting facilities are modified, the owner must submit technical analyses (e.g., air modeling) to demonstrate continued compliance with Regulation 346. Only then is a new Certificate of Approval issued by the Ministry of the Environment.

Countdown Acid Rain Regulations

Total NOx and SO_2 emissions from OPG's fossil fuel facilities are capped under the Countdown Acid Rain Program. From 1986 to 1989, Ontario Hydro (to which Ontario Power Generation is the successor company) had to meet a SO_2 emissions cap of 370 kilotonnes/year, followed by a lower cap of 240 kt/yr for 1990 to 1993, and a cap of 175 kt/yr beginning in 1994. The 1994 regulation also set a cap of 215 kt/year on total acid gas (sulphur dioxide and nitric oxide) emissions. If SO_2 emissions fall, NOx emissions will be permitted to rise, provided the sum of SO_2 and NOx does not exceed 215 kilotonnes. The 1994 limits continue to apply today to OPG, under Ontario Regulation 153/99.

OPG's voluntary commitments to limit NOx and CO_2 emissions

Nitrogen oxides (NOx) – In 1991, the Ontario Power Generation predecessor Ontario Hydro made a voluntary commitment to limit its NOx emissions to 38 kilotonnes a year beginning in 2000. This has become Ontario Power Generation's contribution toward Ontario's Anti-Smog Action Plan and represents a 24 per cent (12 kt) reduction from 1990 emissions levels. Ontario Power Generation is also participating in the Pilot Emissions Reduction Trading Project (PERT) and has been acquiring NOx credits in anticipation of using them to meet voluntary NOx commitments.

Carbon dioxide (CO_2) – Ontario Power Generation has made a voluntary commitment to stabilize its net greenhouse gas emissions at 1990 levels (26,000 kilotonnes) by the year 2000.

Municipal Strategy for Abatement (MISA)

Regulations developed under the MISA place limits on wastewater effluents discharged directly from nine major industrial sectors. Wastewater limits for OPG's six fossil fuel facilities have been in force since August 26, 1997. Limits are set for the concentration of total suspended solids, oil and grease, iron, aluminum and zinc.

Currently proposed environmental controls

Air Quality Proposals (January 24, 2000)

On January 24, 2000, the Ministry of the Environment announced the proposed direction for environmental regulations for the electricity sector, along with other broader commitments to air quality. The announcement, which was posted to the Environmental Bill of Rights (EBR) Registry for public comment, described proposals for three areas of regulation:

I. Emissions monitoring and reporting;
II. Proposed changes to the Environmental Assessment Act requirements; and
III. Emissions limits and emissions reduction trading.

I. Emissions monitoring and reporting

An Emissions Monitoring and Reporting Regulation (Reg. 227) has been in place since May 1, 2000, requiring electricity generating facilities to monitor and report on 28 key pollutants.

On November 10, 2000, the Ministry of the Environment announced a proposed expansion to Regulation 227. Under the strengthened regulation, the complete list of reported substances would grow to 358, while regulation coverage would expand to include industrial, institutional, commercial and municipal sectors.

Every sector would be subject to specific contaminant lists. Emissions reports would be annual for the calendar year and the smog season, May 1 to September 30. For larger facilities in excess of 73 MW energy input, emissions of sulphur dioxide and/or nitrogen oxides would be reported quarterly if they exceeded specific thresholds. Together with stakeholders, the ministry also plans to develop an air emissions inventory internet site to facilitate public access to reports.

Once in place, Ontario's proposed Mandatory Monitoring and Reporting program would create a comprehensive database that would include criteria air contaminants, greenhouse gases and toxic

air contaminants, such as oxides of nitrogen, sulphur dioxide, volatile organic compounds, carbon monoxide, PM10, PM2.5, particulates, methane, carbon dioxide, nitrous oxide and HCF134a. The program also would:

- provide a comprehensive emissions database to track the progress of air quality initiatives and commitments and to assist in the development of future environmental policy. This comprehensive collection of information would enable government to monitor compliance with air quality programs and regulations;
- provide a level playing field for all sectors in Ontario; and
- create an incentive for further emissions reductions, since all reported data would be made public.

II. Proposed changes to the Environmental Assessment Act requirements

Currently, the Environmental Assessment Act (EAA) as applied to the electricity sector covers only the Ontario Hydro successor companies (Ontario Power Generation and Hydro One) and municipal electric corporations. Under the ministry's proposal, EAA requirements would be based on the environmental effects of an electricity project, rather than its status as public or private.

The ministry is now in the process of finalizing new Environmental Assessment (EA) requirements for the electricity sector.

The proposed changes would recognize three categories of projects:

A. Projects with relatively benign environmental effects: These projects would not be subject to Environmental Assessment requirements;
B. Projects with environmental effects that could likely be mitigated: These projects would be subject to the EAA and be required to go through a screening process, but would not be required to prepare an individual EA on the condition that they successfully complete the screening process; and
C. Projects with known and significant environmental effects: These projects would be subject to individual Environmental Assessments.

The preceding categories are based on the following principles:

- giving credit to proponents of environmentally benign or beneficial technologies;
- requiring no EA approvals for small projects that are likely to have only minor, if any, environmental effects;
- ensuring that there is, to the extent possible, a level playing field between technologies with similar potential environmental effects;
- creating more stringent requirements for technology not covered by other approvals (e.g. noise emissions from wind turbines);

- creating more stringent requirements for technologies of a size or type that are likely to cause greater environmental effects (e.g. coal and oil-fired generation); and
- streamlining the assessment process for facilities that make very efficient use of fuel (e.g., co-generation facilities) to provide incentives for their development.

The screening process (for projects in Category B) would require proponents to identify the potential environmental effects of their projects, consult with appropriate agencies and members of the public, and outline measures to mitigate or manage environmental effects.

Two levels of assessment would be possible under the screening process, depending on the potential environmental effects of the project. All projects would be required to go through the screening stage, which would require proponents to identify the potential environmental effects of the project. A more detailed study (called an "Environmental Review") would be required if concerns are raised during the screening stage that cannot be readily addressed. The proponent's screening report would be available to the public and agencies for review. During the review period, members of the public and agencies with outstanding environmental concerns would have the opportunity to request the project's status be elevated to an Environmental Review within the screening process, or to an individual EA.

III. Emissions limits and emissions reduction trading

As part of the January 24, 2000, air quality package, the ministry proposed annual NOx and SO_2 emission caps for Ontario Power Generation's fossil fuel facilities:

- 36 kilotonnes of NOx/year (measured as nitric oxide - NO) - a five per cent reduction from OPG's existing voluntary NOx cap; and
- 157.5 kilotonnes of SO_2/year - a ten per cent reduction from OPG's existing limit under the Countdown Acid Rain Program;

The limits would take effect with the opening of the electricity market. They were also intended as a starting point for further emission reductions. The proposed emissions limits are net limits that would allow capped facilities to use emissions credits gained through emissions trading within Ontario's airshed.

Along with near-term limits, the ministry also proposed a direction for longer-term limits and committed to:

- future NOx limits for the electricity sector that would match or exceed any new U.S. Environmental Protection Agency (EPA) emission standards – if the adoption of these limits resulted in lower emissions in Ontario;
- expanding Ontario's electricity sector emissions caps to include all fossil fuel electricity generators (i.e., beyond OPG's six facilities);
- cutting provincial SO_2 emissions by 50 per cent below the existing provincial SO_2 cap

(885kt) under the Countdown Acid Rain Program. To assist in meeting this target, the SO_2 cap on the electricity sector would be revised, along with existing SO_2 caps for Ontario's nickel smelters. Sulphur dioxide emission caps would also be developed for other major emitting sectors; and

- the long-term target to reduce provincial NOx emissions by 45 per cent below 1990 levels as outlined in the Anti-Smog Action Plan. To assist in meeting the ASAP NOx target, NOx emission caps would be developed for other major emitting sectors.

Emissions Reduction Trading

The January 24 announcement also proposed a "Cap, Credit and Trade" emissions trading program. Such a program is an innovative way in which to provide emitters with incentive to achieve emissions reductions above and beyond regulated requirements. At the time, the core elements of the trading proposal were laid out. Detailed trading rules would be developed in consultation with stakeholders and posted to the EBR Registry for comment.

Core elements of Ontario's proposed emissions reduction trading program include:

- government specifies emissions caps and distributes allowances for specific groups of emitters;
- emitters use market mechanisms to meet their emissions caps;
- capped emitters are deemed to have met their responsibilities under this system if their annual emissions are less than the total of the allocations they own and retire, plus the emissions reduction credits they own and retire; and
- non-capped emitters in the airshed produce emissions reductions credits voluntarily through investments or operational measures. They may bank these credits for their own future needs or for sale to capped entities.

The ministry is currently working to finalize the proposed emissions reduction trading rules.

Emissions Performance Standards

Emissions Performance Standards (EPS) – also referred to as emissions rate standards – would apply to all electricity generated or sold in Ontario (by coal-or-oil-fired plants greater than 25 MW). The purpose of setting EPS is to protect Ontario's air quality by ensuring that out-of-province electricity generators wishing to sell in the Ontario market are not operating at unacceptable environmental standards.

Emission Limits - Carbon Dioxide

Under the Kyoto Protocol, Canada is committed to reducing its greenhouse gas emissions by six per cent below 1990 levels between 2008 and 2012. A national process involving stakeholders and federal, provincial and territorial governments is underway to develop Canada's response.

Ontario has offered the document "Air Quality and Climate Change – Insights, Opportunities, Solutions" as part of Canada's First National Business Plan to address climate change.

Emission Limits - Mercury

As of 2000, Ontario had reduced provincial mercury emissions by 78 per cent of 1988 levels. Under the Canada-Wide Standards (CWS) process, Ontario has already set mercury release limits for incinerators and is currently developing mercury standards for coal-fired power generation, which are expected to be finalized by the fall of 2002.

Ozone Annex

The Canada-US Air Quality Agreement was signed in March, 1991 to address transboundary air issues. Initially, the agreement focused on acid rain. Adding to the provisions of the Agreement, Canada's federal government negotiated the 'Ozone Annex', which was signed on December 7, 2000, by federal Environment Minister David Anderson and Frank Loy, U.S. Under-Secretary of State for Global Affairs.

The Ozone Annex specifies emissions reductions for three major sectors in both Canada and the U.S.: industry, transportation and electricity. The emissions limits for the electricity sector in both countries, however, are set for regions that rely on coal-fired plants. The current Ozone Annex caps would be too high to bring about emissions reductions from a fleet of natural-gas-fired or renewable-energy stations. The terms of the Annex allow the use of coal as a future power plant fuel. In signing the Ozone Annex, the federal government has accepted that although the use of coal generation will continue, measures are needed to address their emissions.

By targeting the key smog precursor pollutants nitrogen oxides (NOx) and volatile organic compounds (VOCs) on both sides of the border, the Annex will mitigate the effects of transboundary air pollution from the U.S. and reduce smog levels in Ontario. Under the Annex, Ontario's electricity sector in southern Ontario will be subject to a NOx emissions cap of 39 kilotonnes – down approximately 50 per cent from 1998 emission levels. (Note that the cap is specified as NO_2. This cap is equivalent to 25 kilotonnes of NOx measured as nitric oxide - NO).

The Ozone Annex also defines a region in each country referred to as a Pollution Emission Management Area (PEMA) to which the obligations of the Annex apply. In Canada, the PEMA includes central and southern Ontario and southern Quebec. In the United States, the PEMA includes 18 states stretching from Wisconsin to Maine, plus the District of Columbia.

CHAPTER 6

Options for Maximizing Environmental Performance

6. OPTIONS FOR MAXIMIZING ENVIRONMENTAL PERFORMANCE

This section examines the technologies and fuel conversion options available to improve the environmental performance of coal-fired power stations. The examined technologies target the four key emissions from coal-generated power: nitrogen oxides, sulphur dioxide, carbon dioxide and mercury.

Nitrogen oxides (NOx)

NOx reduction technologies for boilers come in two categories:

- **Combustion controls** reduce NOx formation during the combustion process. Examples include operational modifications, low-NOx burners (LNBs), gas re-burning, and overfire air (OFA);
- **Post-combustion controls** reduce NOx in the exhaust gases after they have formed. Examples include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR).

Low-NOx Burners are more recent designs that optimize parameters of the combustion process such as fuel/oxygen and zones of peak temperature to limit NOx formation. Operational practices and computer software that monitor the combustion process to maximize efficiency are often used in combination with low-NOx burners. Low-NOx burners can typically achieve NOx reductions between 30 and 65 per cent from uncontrolled levels and are the primary technology currently used to meet existing U.S. Acid Rain NOx Program requirements. On average, units achieve emission rates of 0.36 to 0.45 lb/mmBtu representing reductions of about 45 per cent from 1990 levels.

In many gas facilities, combustion controls combined with fuel characteristics and the higher efficiency of natural gas are capable of achieving NOx levels of less than 0.15 lb/mmBtu. For coal facilities to achieve this rate, more expensive post-combustion controls are necessary.

Selective Non-Catalytic Reduction processes reduce NOx emissions by injecting ammonia (or urea) into exhaust gases to react with NOx, producing nitrogen and water. Temperature must be controlled (2,000 F). Removal efficiencies of up to 60 per cent are possible with this technology. Selective Non-Catalytic Reduction processes result in the release of a small amount of ammonia - referred to as "ammonia slip" - into the atmosphere.

Selective Catalytic Reduction (SCR) reduces NOx by reacting it with ammonia (or urea) in the presence of a ceramic or metal catalyst. Nitrogen oxides reductions of up to 90 per cent can be

achieved with this technology. Capital costs are high but have recently come down significantly due to a higher demand for SCR systems. The downside of SCRs is that the catalyst is expensive and can be poisoned by contaminants in the flue gases, reducing its efficiency and life.

The U.S. EPA NOx SIP Call established NOx emission caps for the five-month ozone season from May to September. The caps were established under the assumption that fossil fuel electricity generation in each state would achieve an average emission rate of 0.15 lb of NO_2 per mmBtu of input energy. The 0.15 lb/mmBtu emission rate is based on what the EPA determined could be achieved by installing SCRs on existing facilities.

A limited number of stations in the U.S., particularly in the area of the Ozone Transport Commission (OTC), are using post-combustion controls such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). More stations will need to employ post-combustion controls when the OTC program is fully implemented in 2003, and in other states when the NOx SIP Call proceeds.

In recent years, permits issued by the U.S. EPA for new gas-fired facilities have required SCR with emission rates of 0.02 lb/mmBtu.

Sulphur dioxide (SO_2)

In Ontario, operators of boilers burning fuels that produce sulphur emissions in excess of regulated limits have two major compliance options:

- switch fuels to low-sulphur coal or natural gas; or
- employ flue gas de-sulphurization technologies.

In the U.S., a third option is the purchase of SO_2 credits (allowances) on the open market.

Flue gas de-sulphurization technologies can be divided into two types of processes - wet and dry (or semi-dry). Other SO_2 removal technologies are available but are not yet used widely. In North America, wet flue gas de-sulphurization technology is used roughly nine times as often as dry or semi-dry.

Wet FGD Processes remove SO_2 from the flue gas by reaction with a lime-based (occasionally sodium-based or magnesium-based) solution. Under ideal conditions, wet FGD can achieve up to 99+ per cent removal of SO_2.

An added benefit of wet FGD systems is the removal of fine particulate matter (because of the intimate contact of the gas and liquid phases) and trace metals (including mercury). One disadvantage is the relatively high level of energy needed to operate the wet FGD system. Reaction of the SO_2 with the calcium produces calcium sulphate - also known as gypsum. If the

gypsum is pure enough it may be used to produce wallboard or drywall. Otherwise it must be disposed of in landfills at significant cost.

Dry and Semi-dry FGD Systems involve the injection of a solid (usually calcium-based) or slurry sorbent - for example, limestone into a furnace or flue gas duct. Reaction byproducts are collected together with fly ash by the existing particulate matter pollution control device.

Dry and semi-dry FGD systems tend to be less expensive than wet FGD (both capital and operating costs), but have lower SO_2 removal efficiencies and higher chemical usage rates. The products of reaction associated with dry and semi-dry systems are generally not of any commercial value.

Mercury (Hg)

The performance of technologies for removing mercury has not been widely demonstrated.. Effective removal depends on many factors, including the form of mercury present in the raw coal and in the post-combustion flue gases, as well as levels of chloride and sulphur.

Installation of post-combustion controls designed for NOx or SO_2 can result in significant Hg removal as a co-benefit, and vice-versa. Emissions reduction strategies for mercury from coal stations are currently being evaluated, which may also have co-benefit reductions of SO_2 and NOx.

Selective Catalytic Reduction does not in itself contribute to reduced mercury emissions, and alone may actually make the local mercury issue worse. Selective Catalytic Reduction oxidizes mercury so that more ionic mercury (versus non-ionic mercury) is emitted. However, because Selective Catalytic Reduction increases the amount of ionic mercury, it makes downstream capture of mercury with other equipment more efficient, including SO_2 wet scrubbers, carbon injection or baghouse (filter) installation.

Wet scrubbers typically show a 50 per cent removal efficiency for most coals - higher ionic ratios in Lakeview, Lambton and Nanticoke suggest at least a 50 per cent reduction. The excess mercury ends up bound in the lime sludge - which can be released if the sludge is recycled or used in building products.

Dry lime injection and baghouse combinations with and without Selective Catalytic Reduction will likely achieve a 50 per cent reduction from present levels. Other reduction technologies are available or being developed that may achieve reductions of mercury up to 90 per cent without adding carbon. Carbon injection and a baghouse (filter) without SCR, which is likely to be the U.S. EPA MACT (Maximum Available Control Technology) limit, achieves about 90 per cent control efficiency, and about 95 per cent with SCR.

Advanced coal-cleaning, using surfactants rather than water, can reduce mercury content in some coals by up to 20 per cent beyond conventional cleaning. Development work is underway to achieve additional efficiencies.

Natural gas is essentially mercury-free. Clean-coal technologies are being explored that can achieve performance rates closer to natural gas and equal to MACT (Maximum Available Control Technology).

Carbon dioxide (CO_2)

There are no commercially-available technologies for removing CO_2 from flue gases. Improvements in general station efficiency may reduce CO_2 emissions, but these improvements may also be minimized by the added fuel (and therefore, the added CO_2 emissions) needed to support such improvements. For example, CO_2 emissions will increase with the addition of many of the above post-combustion emissions controls.

Conversion to natural gas is the only current means available of achieving significant CO_2 reductions.

Gas technologies

Compared to coal, burning natural gas to produce electricity has significant environmental advantages. Natural gas burns cleaner, creating much lower NOx and CO_2 emissions, and virtually no SO_2 emissions or emissions of hazardous air pollutants such as mercury.

Converting from coal to natural gas can be done in a number of ways:

Conversion of Existing Boilers

Coal is the fuel used at all of OPG's fossil fuel generating stations except Lennox. Fuel accounts for approximately 75 per cent of the total production cost of OPG's fossil fuel generation. The existing conventional steam boilers in use at OPG's six fossil fuel facilities operate at an average efficiency of about 34 per cent. In other words, one-third of the energy in the fuel is converted to electricity while the other two-thirds is unused waste heat.

These boilers can be converted to burn natural gas with an investment of approximately $20 to $60 per kilowatt. Coal is considerably cheaper than natural gas. If converted, the low efficiency of OPG's existing boilers - combined with the high price of natural gas - would result in high fueling costs. As a result, this technology would generally be restricted to providing power only when demand for electricity is high enough to cover costs. Natural gas can also be used in various gas turbine configurations:

Simple Cycle Gas Turbine

Simple Cycle Gas Turbine systems would be somewhat more efficient than converting OPG's existing boilers. These systems operate at about 40 per cent efficiency. Similar to converting OPG's existing boilers, these systems have high fueling costs, and therefore would only find use when electricity demand was high enough to cover costs.

Combined Cycle Gas Turbines

The exhaust from a gas turbine is hot enough to be used to produce steam, which can drive a steam turbine and generator. A system which combines a gas turbine and steam turbine is known as a Combined Cycle Gas Turbine system. Today's Combined Cycle Turbine systems operate at up to 58 per cent efficiency. This system is the most widely used for new large-scale electricity generation from natural gas. Several new combined cycle generation plants are being proposed in Ontario. A combined cycle plant requires a large capital investment - around $750 per kilowatt of capacity. The higher efficiency of a combined cycle plant partially compensates for higher cost of fueling with natural gas.

Co-generation

The most efficient systems use the exhaust heat from any of the generation processes to provide steam or hot water, which is then used for industrial processes or space heating. This is known as co-generation. Co-generation can achieve efficiencies of 80 per cent but is limited to locations where a suitable heat demand exists. Practical applications have not been found for the existing coal plants.

Emissions performance from gas-fired facilities

Figure 6.1 on the following page compares emissions rates from OPG's existing stations with those achievable from converting existing boilers to natural gas, and from installing new combined gas turbines. For this comparison, emissions rates are available for the pollutants NO_X, SO_2, CO_2 and mercury.

Table 6.1 - Comparison of Emission Performance

Pollutant	Existing OPG Fossil	Emission Controls on Coal		Conversion to Gas Burner at OPG Stations		New Combined Cycle Gas with SCR	
	Rate (kg/MWh)	Rate (kg/MWh)	% Change	Rate (kg/MWh)	% Change	Rate (kg/MWh)	% Change
NOx	1.2	0.45 **(1)**	- 63%-80%	0.7	- 42%	0.041	- 97%
SO_2	4.6	0.75 **(2)**	- 84%	0.018	- 99%	0.011	- 99+%
CO_2	890	-	slight increase with **(1)** and **(2)**	530	- 40%	371	- 58%
Mercury	0.017 (g/MWh)	0.005 (g/MWh)	- 70% **(3)**	negligible	- 99+%	negligible	- 99+%

(1) SCRs with use of low-NOx burners
(2) FGDs with use of high-sulphur coal
(3) Expected capability of technologies under development

CHAPTER 7

The Framework for Strengthening Environmental Protection

7. THE FRAMEWORK FOR STRENGTHENING ENVIRONMENTAL PROTECTION

The review has shown that investments in coal stations have been made (until recently) on the basis of limited operation for these stations. Emissions at some stations in Ontario could increase further as a result of a move to a competitive system if the stations are found to be competitive with those in the U.S. Greater efforts should be made to reduce emission rates at all stations. Units that are expected to operate as fossil fuel plants should be moving to state of the art pollution control equipment. However, in a competitive market, future loading of any given unit will be uncertain and station operation will vary from year to year.

Proven and cost-effective emission control technologies are available that can be added to existing coal stations to achieve significant reductions. Selective Catalytic Reduction (SCR) can reduce NOx emissions by up to 80 per cent, while de-sulphurization scrubbers can reduce SO_2 emissions by 90+ per cent. The use of gas as a fuel would eliminate SO_2 and mercury emissions and greatly reduce NOx and CO_2.

Tighter environmental controls can be imposed through regulations for individual stations (aimed at the station as a whole or at specific units) or through regulations capping emissions from the electricity sector (a systems approach).

Regulations requiring emission reductions from specific stations should be used where the issues are local (as opposed to regional). Lakeview stands out as a heavily-polluting station (SO_2, Mercury, NOx) located in the midst of a heavily-populated area. This fact, combined with the station's important role in providing system reliability in the GTA, warrants special attention.

Regulations taking a systems approach should be used to address regional air issues. A systems approach allows tough emissions standards to be met while encouraging a competitive market.

Meeting Ontario's emissions targets

Reducing air emissions has traditionally been achieved through strict regulatory mechanisms that target specific sources of pollution – such as an individual power plant. However, many jurisdictions at the forefront of environmental policy have been moving away from this "command and control" model for specific pollutants towards a more integrated approach to improving air quality. This new model gives the regulated community more flexibility in how to reduce their emissions to meet strict government limits.

In the case of power plants, for example, a traditional command and control approach would require site-specific actions to reduce emissions from individual stations - like mandating the conversion to cleaner fuels or the use of new emission reduction technologies. A more integrated strategy would leave it up to the plant owners as to what mechanisms they choose to achieve government-prescribed reductions. Emission caps are an example of one such strategy.

Under an integrated approach, the government would set the overall provincial reduction cap for the sector and industry would be allowed to determine where and how they achieve their reductions. Individual stations would be integrated into a broader market that collectively must meet strict government limits. Stringent and gradually decreasing limits, coupled with emissions reduction trading, are fundamental components of this approach. Industry would be provided with market incentives to reduce pollution in a competitive marketplace that stimulates innovation, rewards efficiency and speeds development.

Defining stringent caps as early as possible will provide more certainty for power station owners and potential investors. The Ontario Government may continue its practice of establishing annual caps rather than seasonal caps – especially given medical evidence that NOx emissions cause health problems year-round.

CHAPTER 8

Findings and Recommendations

8. FINDINGS AND RECOMMENDATIONS

The government's intention, when it announced the moratorium on the sale of all coal-fired electricity plants, was to ensure environmental protection measures be in place prior to the start of a competitive electricity market.

The following findings and recommendations summarize the framework needed to allow the moratorium to be lifted.

Findings

1. Significant air quality challenges for Ontario are posed by emissions of nitrogen oxides (NOx), sulphur dioxide (SO_2), carbon dioxide (CO_2) and mercury. While causing smog, acid rain, toxic deposition and contributing to the threat of climate change, these key pollutants also affect human health.

2. Ontario is part of a regional airshed that stretches from the U.S. midwest into Quebec and the northeastern U.S. Within this regional airshed, there are localized airsheds with unique challenges largely due to their dense urban makeup.

3. Ontario's domestic contributions to air pollution are far outweighed by pollutants entering the province from U.S. sources. Prevailing wind patterns make U.S. pollution sources the largest contributors to air pollution in Ontario. This is especially true for smog, on average more than 50 per cent of Ontario's smog is due to pollution from south of the border.

4. To combat air pollution, the government is employing an air quality strategy that is integrated, comprehensive and balanced. Ontario's strategy targets a variety of sectors simultaneously - including transportation, industry, power and residential - while continually growing in scope to ensure broader contributions across the province. All individuals and sectors must continue to do their fair share toward eliminating or reducing the emissions that lead to air pollution.

5. Ontario is currently ahead of neighbouring U.S. states in reducing SO_2 emissions from its electricity sector. The province's fossil fuel stations also meet existing U.S. EPA national standards. However, further emissions reductions are needed for Ontario to meet its current provincial and national commitments, which are:

    - a 45 per cent reduction in NOx from 1990 emission levels as part of ASAP;
    - a 50 per cent reduction in SO_2 under the Countdown Acid Rain Program;

- to meet or exceed U.S. EPA NOx SIP CALL limits when they are in place;
- to develop mercury standards as part of the Canada-Wide Standards process; and
- to provide its fair-share contribution to Canada's national effort to reduce greenhouse gases under the Kyoto Protocol to address climate change.

6. Ontario's coal-fired power plants are among the major sources of key air pollutants in the province. The Lakeview Generating Station is the oldest and least efficient plant in OPG's fleet and has the unique distinction of being located in a heavily-populated urban area. Therefore, the station has potentially greater air pollution effects on its local airshed than Ontario's other coal stations.

7. Cost-effective technologies exist to achieve significant reductions of NOx and SO_2. However, the effectiveness of technologies for reducing CO_2 and mercury have not been clearly demonstrated. Despite significant investments by OPG in emissions reduction technologies, more action is needed to reduce emissions of key pollutants from the province's coal stations in order for Ontario to meet its provincial and national commitments.

Recommendations

An appropriate environmental protection framework to allow the government to lift the moratorium on the sale of coal-fired power plants will exist once the following recommended actions are adopted.

1. Tough emissions limits (caps) for Ontario's electricity sector must be put in place. Emissions caps act as an incentive for power generators to implement cleaner technologies and more stringent emission control systems. Ontario's caps must be strict enough to ensure the province is able to meet its long-term air quality commitments.

2. The Lakeview plant be required to cease burning coal as soon as the short-term system reliability needs of the Greater Toronto Area can be addressed.

   While air pollution from coal-fired electricity generation affects the entire airshed, it also has local effects. The Lakeview Generating Station is a coal-fired power plant that stands out as a relatively old, heavily-polluting station located in the west of Canada's largest urban conglomeration, the Greater Toronto Area (GTA). Currently, Lakeview generates eight per cent of the GTA's NOx emissions and more than 25 per cent of the region's SO_2. Further, the station is also a major source of local mercury emissions, generating 83.2 kg/year in 1999.

3. Ontario continue to participate in the national process to address climate change and the Canada-Wide Standard setting process to determine limits for mercury.